FINAL DECISION

CitiPower
Distribution Determination
2021 to 2026

Overview

April 2021

AUSTRALIAN
ENERGY
REGULATOR

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Executive summary

The Australian Energy Regulator (AER) works to make all Australian energy consumers better off, now and in the future. We regulate energy networks in all jurisdictions except Western Australia. This final decision sets out the amount of money CitiPower can recover from electricity consumers for using its network over the 2021–26 regulatory control period.

CitiPower owns and operates one of the five electricity distribution networks in Victoria and services around 330 000 customers in Melbourne's central business district and inner suburbs. On 31 January 2020, CitiPower submitted its proposal for the five year regulatory control period commencing 1 July 2021. On 3 December 2020, CitiPower submitted a revised proposal based on the AERs draft decision of 30 September 2020.

CitiPower accepted many parts of our draft decision and demonstrated an ongoing commitment to consumer engagement in its revised proposal. CitiPower’s revised proposal submitted a materially reduced capital expenditure (capex) forecast. Although lower than the initial proposal, we found the total capex forecast not acceptable. In our final decision we set a substitute prudent and efficient capex forecast for the next regulatory control period. We had no material differences with CitiPower’s revised operating expenditure (opex) proposal and our final decision finds it acceptable.

CitiPower also proposed to recover under recovered revenues in 2020 due to COVID-19 across the next regulatory control period rather than recover it all in one year. Having considered the exceptional circumstances, the materiality of the amount and its price impacts for consumers, we have accepted this approach to smooth the recovery.

We are satisfied that the amount of money we have allowed CitiPower to recover from consumers is no more than necessary to replace ageing infrastructure and operate its network in a safe and reliable manner in the long-term interest of consumers.

CitiPower can recover $1485.8 million ($ nominal) from its consumers over the 2021–26 regulatory control period. In real terms, this is 7.8 per cent lower than the revenue allowed for in our 2016–2020 final decision and leads to lower network charges for CitiPower’s consumers from the next regulatory control period.

The revenue we allow forms the distribution network component of retail electricity bills, making up about 20 per cent of a standard residential bill (25 per cent for small businesses).

We estimate that CitiPower's distribution network and metering charges in the first year of the 2021–26 regulatory control period will drop by $46 (3.2 per cent) for residential consumers and $151 (2.6 per cent) for small business consumers, relative to the charges in 2020. Thereafter, these charges are estimated to increase by $1 (0.1 per cent) and $4 (0.1 per cent) per year respectively.

Consumers have already seen changes from last year’s prices because new distribution network charges were passed through to Victorian consumers for six months on 1 January 2021 with the introduction of the *National Energy Legislation Amendment Act 2020* (Vic) (NELA Act).[1] In making this final decision we updated a range of components that were used to calculate the lower distribution network charges that were passed on to consumers on 1 January 2021. In particular, we updated the rate of return to reflect movements in interest rates and our revised estimate of expected inflation. As a result of these updates, distribution network charges starting from 1 July 2021 will be 2.3 per cent higher than the distribution network charges that were set on 1 January 2021, but will still be lower than the distribution network charges that were in place in 2020. We still need to consider other factors that will impact the final distribution network charge that consumers and business pay – these will be considered when we assess CitiPower's annual pricing proposal.[2]

In making this final decision we have had regard to a range of sources including CitiPower's revised proposal, submissions received, as well as analysis undertaken and published by us.

CitiPower's engagement with consumers

A key development of the 2021–26 determination has been the positive shift by the distributors in relation to improved consumer engagement.

In recognition of this evolution, in our draft decision, we developed a framework[3] to assess the consumer engagement activities of the Victorian distributors. This framework informed how we viewed this engagement in relation to the initial expenditure proposals and our overall assessment. Stakeholder submissions provided positive support and feedback on this approach and we plan to undertake further stakeholder consultation on the future design of the framework following completion of the Victorian reset.

We recognise that consumer engagement can take many different approaches and to assist in the final decision we have continued to refer to our framework as outlined in the draft decision, which provides a benchmark for the discussion and is replicated at appendix C. We acknowledge that each distributor approached engagement differently and CitiPower, Powercor and United Energy worked together across the three

1 The intention of the NELA was to change the timing of the regulatory control period for electricity distribution networks from a calendar year basis to a financial year basis, to align with other NEM states. We separately assessed the total allowed revenue for CitiPower for the six month period from 1 January 2021 to 30 June 2021. See our final decision of 28 October 2020 at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/citipower-determination-2021-26/aer-position#step-72920.

2 See Pricing proposals & tariffs webpage on the AER's website: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs

3 AER, Draft decision, CitiPower distribution determination 2021–26, Overview, September 2020, Table 7, p. 42.

networks to achieve their consumer engagement program. In developing their proposal, they sought to learn about their customer's values and preferences.[4]

Our draft decision stated it was difficult to understand how consumer engagement learnings had influenced the initial proposals. We recognise that CitiPower, Powercor and United Energy have proactively responded to actively involve customers in the decision-making process with the formation of their new Customer Advisory Panel (CAP). Ultimately, we maintained a bottom-up assessment of CitiPower's capex, as we do not think that, in conjunction with our top-down technical analysis, sufficient customer engagement information was provided to persuade an alternative assessment. However, it does not prevent CitiPower from spending from their aggregate capex on projects shown to be of value to its customers.

Consumer engagement models will continue to mature over time. Ongoing development of the framework will support businesses to develop proposals that are prudent and efficient, and demonstrate the express views and support of consumers.

Poles and asset management

While CitiPower has significantly reduced its pole forecast in its revised proposal, we have retained our estimate from our draft decision. This is because we were not satisfied that it provided sufficient evidence to support a 115 per cent forecasted step up from its current period spend. The forecast step up reflects CitiPower's intention to adopt Powercor's proposed asset management practice.

We support CitiPower's plans to improve its wood pole inspection practices. These improvements will allow CitiPower to collect more information about the condition of its poles, better identify and target highest-risk poles and therefore prioritise as well as consider different types of options other than replacement. But improvements in asset management practices in and of themselves does not mean materially higher volumes are required, especially to the levels proposed by CitiPower. We note that CitiPower's proposal was overwhelmingly focused on Powercor's network requirements, and given the different characteristics and performances of the networks, we are not satisfied that this forecasting approach results in a prudent and efficient poles replacement capital expenditure (repex) forecast.

We are satisfied that our substitute estimate, which is in line with its current regulatory control period spend, will provide CitiPower with sufficient funding to meet its capex objectives, including supporting safe and reliable provision of network services, under the National Electricity Rules (NER). This is because at current levels of historical capex it maintained low failures rates and performed well on other safety indicators.

4 Through CitiPower, Powercor and United Energy's engagement program 'Energised 2021–26' they and engaged with 11 000 customers and stakeholders through around 2.5 million 'touch points'. See AER, Draft Decision, CitiPower distribution determination 2021–26 Overview, September 2020, p. 4

Ensuring consumers pay no more than necessary for safe and reliable services

Ensuring consumers pay no more than necessary for safe and reliable electricity is a cornerstone of the regulatory determination process. We must assess whether a business' proposal is a reasonable and realistic forecast of how much money it needs for the safe and reliable operation of the network. It also involves encouraging distributors to explore how they can provide better services at lower cost through a range of incentive schemes.

Our final decision approved most of CitiPower's revised expenditure proposal, the main element we did not approve was capex.

We have not accepted CitiPower's revised total forecast capex of $633.3 million. Overall, it did not provide sufficient evidence that a step up of 16 per cent, relative to its current period spend, is required over the forecast period. We undertook a detailed bottom-up assessment of the capex categories where the top-down metrics indicated the forecast may not be prudent and efficient. Our detailed bottom-up review also helped inform our substitute estimate.

On a number of safety-related capex, CitiPower provided further supporting information. We are satisfied that the evidence supports the inclusion of some of CitiPower's proposed forecast repex such as for circuit breakers. However, as noted above, the evidence did not support the inclusion of its proposed poles repex in the prudent and efficient total capex amount.

We are satisfied that our substitute capex forecast, which is 7 per cent below CitiPower's, is sufficient for it to maintain the safety and reliability of its network. This is because our substitute capex forecast of $589.9 million is 8 per cent higher than its current period spend. Our substitute estimate does not preclude CitiPower spending more or less on capex in aggregate or for the component programs.

Having reviewed an application by CitiPower, Powercor and United Energy, we determined that the annual payments made by the Victorian distributors to Energy Safe Victoria (ESV) is a jurisdictional scheme.[5] This final determination includes a decision on how CitiPower is to report to the AER on its recovery of amounts for the scheme and on adjustments made in pricing proposals to account for over or under recovery. From the start of the 2021–26 regulatory control period ESV levy costs will be recovered through annual prices rather than the allowed revenue we set in our decision.

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5 See https://www.aer.gov.au/communication/aer-makes-determination-on-cpus-application-for-a-jurisdictional-scheme .

Transition of the energy system

Facilitating the transition of the energy system is a key theme for this Victorian regulatory determination process. Mechanisms such as expenditure to physically accommodate greater solar exports, tariff price signals and demand management initiatives can help. We consider the transition of the energy system so important that we have made incentivising networks to become platforms for energy services a strategic objective in our regulation of networks.

CitiPower accepted our draft decision on the amount of capex required to facilitate and integrate distributed energy resources (DER) on its network. Our decision supports CitiPower accommodating solar PV growth on its networks to achieve consumer expectations regarding the Victorian Government's Solar Homes program.

We have engaged extensively with stakeholders in the development of consistent DER integration expenditure guidelines. We published CSIRO and CutlerMerz's final value of DER (VaDER) methodology study in November 2020. However, the Australian Energy Market Commission (AEMC) recently published draft rule changes which have implications for our DER integration expenditure guideline and which will delay its finalisation.[6]

Cost reflective network tariffs also have an important part to play in the energy transition by incentivising the location and use of DER to optimise benefits to consumers and networks.

We are encouraged by the Victorian distributors' efforts to progress network tariff reform during the 2021−26 regulatory control period. The distributors moved from opt−in to opt−out assignment to the new default time of use tariff for consumers receiving a new meter or who upgrade their connection. By working collaboratively with their stakeholders[7] they developed small consumer tariff proposals with aligned, more targeted peak charging windows. We are also pleased to see the Victorian distributors reassigning small consumers on legacy cost reflective tariffs to new and more targeted default time of use tariff.

We engaged rigorously with the electric vehicle (EV) sector and heard many different perspectives. We encourage EV charging station and energy storage proponents to engage with the Victorian distributors on tariff trials. We see trials as a valuable way of proving out new and innovative service models to inform future network tariffs.

Our view is that it is important that EV charging stations face cost reflective network tariffs to minimise new network investment that increases costs for all consumers. Consistent with our view, charging stations which install load limiting devices can access alternative cost reflective tariffs. Our final decision also makes clear, consistent

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6 See https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources .

7 Which included retailers and jurisdictional government entities.

with Victorian Government policy, that once small consumers with an EV are identified they must be assigned to a cost reflective network tariff.

We consider storage assets should both contribute to recovery of network costs commensurate with their network use and see cost reflective price signals to guide their operation. Our final decision on stand-alone grid scale storage connected to the Victorian networks is to assign such consumers according to the usual tariff classes unless they are only providing network support services. Regardless, ownership of storage assets should not affect tariff class assignment.

Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to CitiPower for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

Contents

1 Our final decision

Our final decision allows CitiPower to recover total revenue of $1485.8 million ($ nominal) from its consumers from 1 July 2021 to 30 June 2026. CitiPower is regulated using a revenue cap and incentives are provided to it to reduce costs, improve service quality and undertake efficient investments.

We determine the total CitiPower can recover from customers for the provision of common distribution services (standard control services (SCS)). This forms the basis of CitiPower's distribution tariffs for the 2021–26 regulatory control period. CitiPower's Tariff Structure Statement (TSS) sets out the tariff structure through which it will recover its regulated revenue for SCS from customers.

CitiPower also provides alternative control services (ACS), the costs of which are recovered only from users of those services. ACS services include: ancillary network services, public lighting and total revenue for metering. These costs are considered separately to our building block determination.[8] CitiPower has not proposed to provide any services on a negotiated basis in the 2021–26 regulatory control period.[9]

We have taken CitiPower's consumer engagement into account in developing our final decision. More information is provided at section 3.

1.1 What's driving revenue?

Revenue is driven by changes in real costs and inflation. We assess costs (such as capital and operating expenditure) in real terms (using 2020–21 as a common year) to reveal the underlying cost trends over a number of years or regulatory control periods. The numbers presented in this overview are in real 2020–21 dollars unless otherwise noted. Some impacts of our decision are presented in nominal terms, where required by the rules and to enable customers to see the full impact of our determination inclusive of expected inflation.

The total revenue allowance in this 2021–26 final decision is 7.8 per cent lower than the revenue provided for in our 2016–20 final decision in real terms. Figure 1 shows real revenue decreases from 2020 levels by 10.3 per cent in the first year of the next regulatory control period. After that, CitiPower's revenue allowance is steady with a smaller 1.0 per cent decrease per year.

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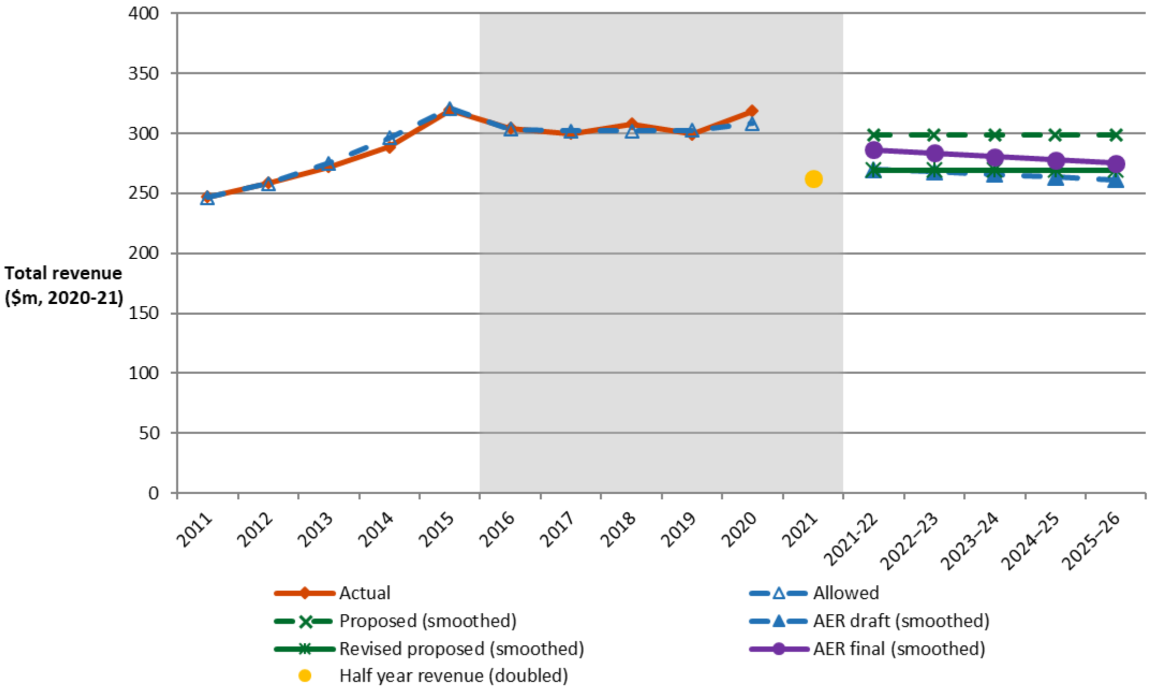
8 We discuss alternative control services in Attachment 16 to this final decision.

9 Our distribution determination for CitiPower includes an approved negotiating framework and negotiated distribution service criteria, as required by the NER. Because CitiPower has not included any negotiated services in its proposal, these elements of our determination will be inactive for the 2021–26 regulatory control period.

Figure 1 Revenue over time ($ million, 2020–21)



Source: AER analysis.

Figure 2 highlights the key drivers of the change in CitiPower's allowed revenue from the 2016–20 regulatory control period, compared to what we expect in the 2021–26 regulatory control period. It illustrates that the largest driver of change is the return on capital building block. The rate of return has decreased from around 6.11 per cent in the 2016–20 regulatory control period to 4.73 per cent for the 2021–26 period. As a result, the total cost of capital had reduced by $184.3 million.[10] In 2019, we reviewed how we calculate the cost of corporate tax and made changes to our approach to align with the latest rulings of the Australian Tax Office. This means we expect the cost of corporate tax for CitiPower will be lower than it was in the past. As a result, Figure 2 also shows a decrease in the cost of corporate tax building block of $64.6 million.[11] Other changes include:

- Increase to forecast regulatory depreciation by 16.2 per cent. Each year, CitiPower builds new equipment to keep its network running. The cost of this new equipment is added to a cumulative total called the regulatory asset base or RAB. Over time, the cost of this equipment is paid back to CitiPower through depreciation. Because CitiPower added new equipment to its network over the last five years, its RAB is increasing and so is its depreciation. CitiPower's increase in depreciation is also affected by lower expected inflation over the 2021–26 regulatory control period.[12]

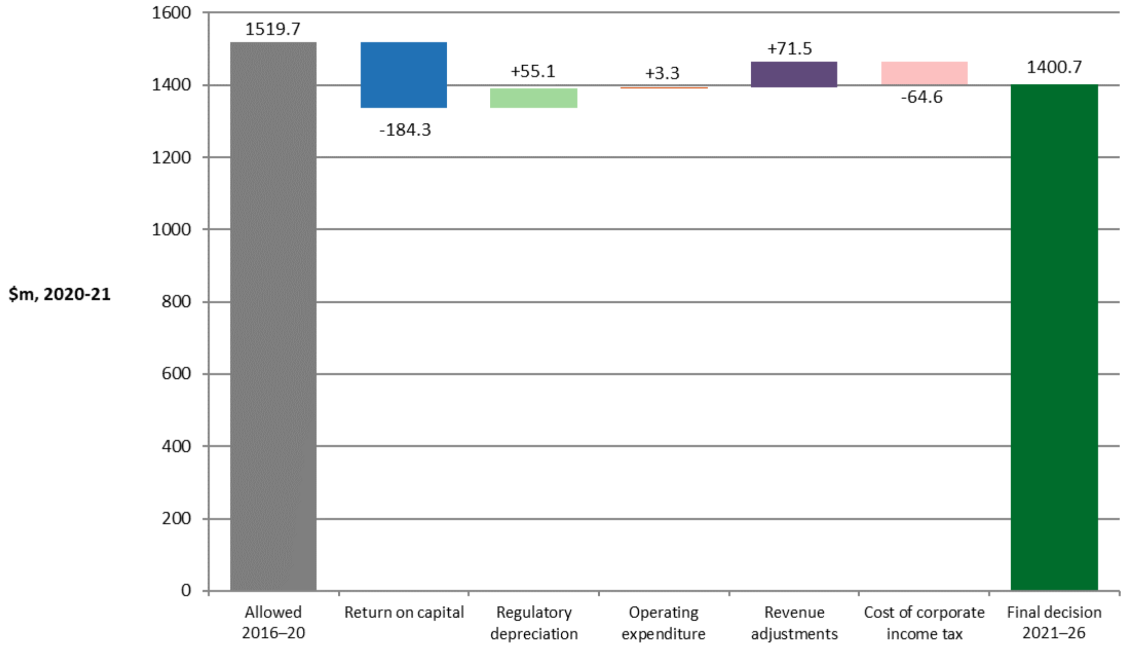
[10] The rate of return is a nominal rate of return unless stated otherwise. The real rate of return has decreased by a similar amount. Please see section 2.2 for further details.

[11] Please see section 2.6 for further details.

[12] Please see section 2.3 for further details.

- Increase of $71.5 million for revenue adjustments. This is mainly driven by our application of capital expenditure sharing scheme (CESS).
- Increase to forecast opex compared to the 2016–20 regulatory control period, by 0.7 per cent.[13]

Figure 2 Change in revenue from 2016–20 to 2021–26 ($ million, 2020–21)



Source: AER analysis.

Figure 3 compares our final decision forecast RAB to CitiPower's revised proposed and actual RAB. This shows that CitiPower's RAB is forecast to increase by around 0.4 per cent in value over the 2021–26 regulatory control period, compared to a 1.0 per cent increase in the current 2016–20 regulatory control period.[14] This difference is mainly driven by lower forecast capex for the 2021–26 regulatory control period compared to capex incurred (and estimated) in the 2016–20 regulatory control period.

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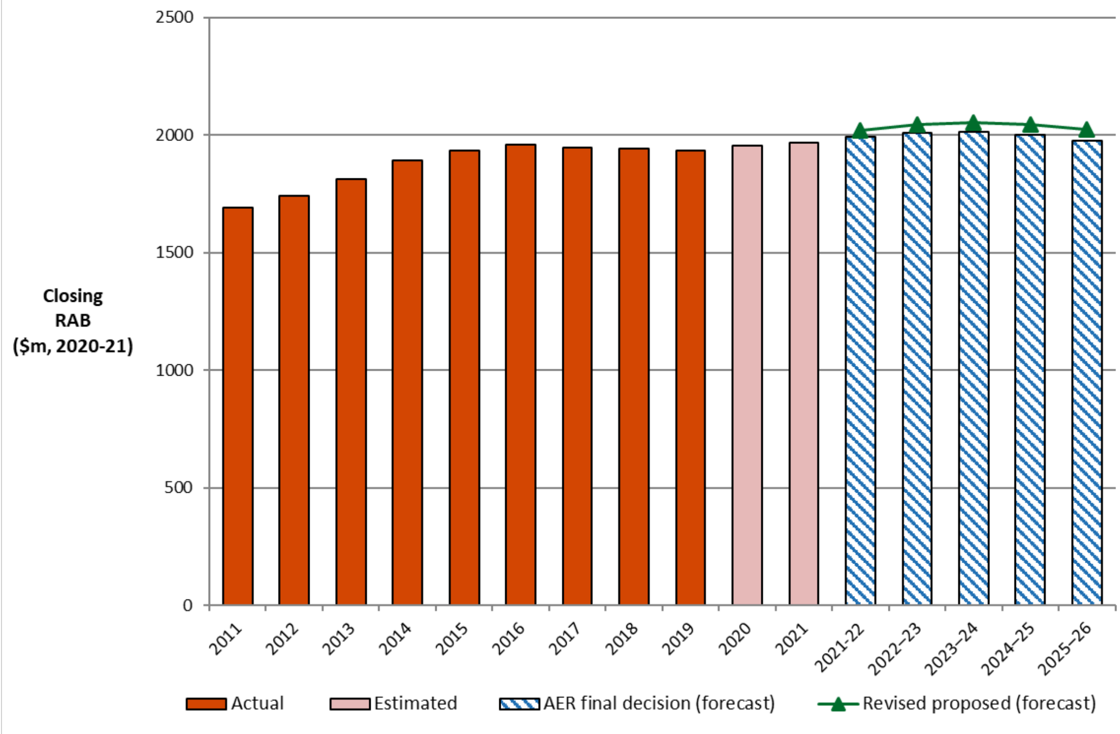
[13] Please see section 2.5 for further details. This comparison is based on converting 2016–20 forecast opex for inflation to 2020–21 dollar terms using lagged CPI.

[14] Please see section 2.1 for further details.

Figure 3 Value of CitiPower's RAB over time ($ million, 2020–21)



Source: AER analysis.

1.2 Differences between revised proposal and our final decision

Our final decision has determined total revenues of $1485.8 million ($ nominal) for the 2021–26 regulatory control period. This is $39.6 million or 2.7 per cent higher than CitiPower's revised proposal of $1446.2 million.

We have largely accepted CitiPower's revised proposal and the difference is due to our updating of the proposed building block amounts using more recent information.

The biggest contributor to the difference between our final decision revenue and CitiPower's revised proposal is regulatory depreciation. Our estimate of the regulatory depreciation of $419.7 million is $31.4 million ($ nominal) or 8.1 per cent higher than CitiPower's revised proposal estimate of $388.3 million ($ nominal). The main driver of this difference is the lower expected inflation which resulted from our inflation review. Our latest version of the Post-tax revenue model (PTRM) (version 5) released in April 2021 amended the way we estimate inflation, in order to improve our estimation in periods of economic instability or sustained periods of low or high inflation.[15] Our final decision estimates expected inflation of 2.00 per cent, lower than CitiPower's estimate of expected inflation of 2.37 per cent.

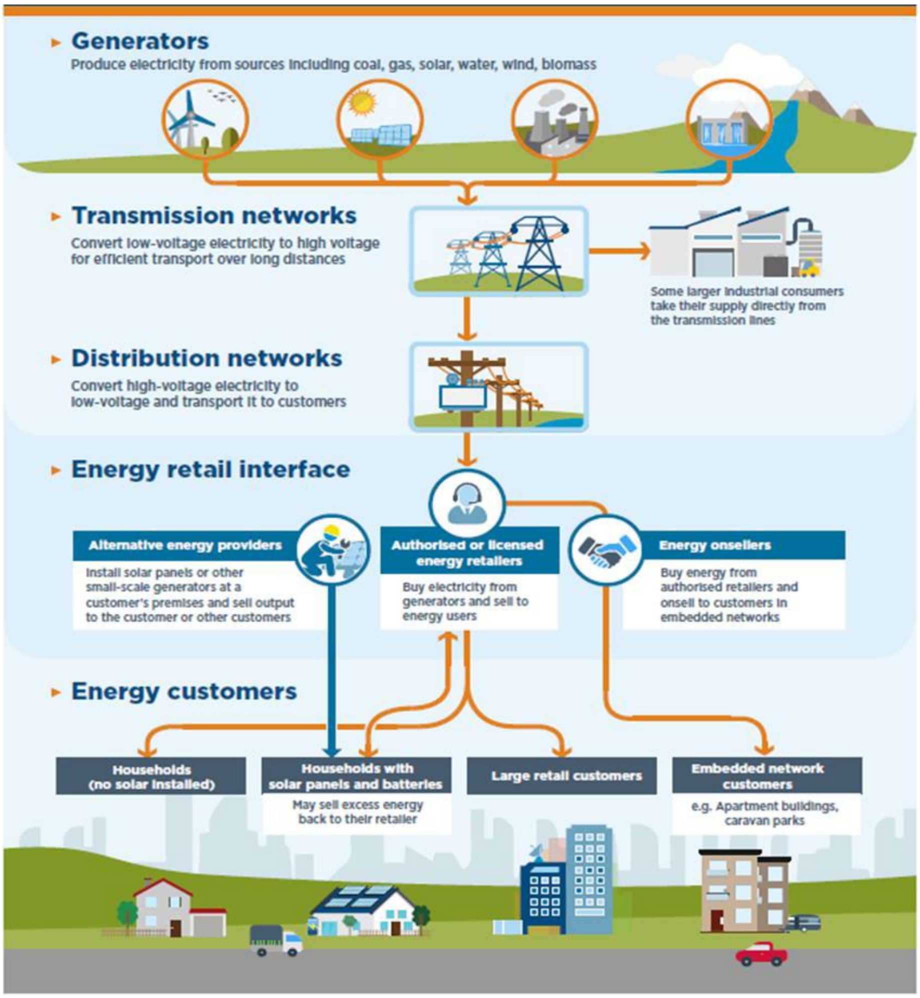
15 AER, *Final position paper - Regulatory treatment of inflation*, December 2020, p. 6.

Based on evidence before us, we are not satisfied that CitiPower revised proposed forecast capex of $633.3 million ($2020–21) reasonably reflects prudent and efficient costs. Our substitute capex forecast is $43.4 million ($2020–21) or 6.8 per cent lower than the revised proposal. This leads to a lower forecast RAB than CitiPower's revised proposal.

1.3 Expected impact of our final decision on electricity bills

CitiPower's distribution network SCS charges make up around 20 per cent of the total residential bill and 25 per cent of the total small business retail electricity bill. Our decision also covers charges for revenue-capped metering services (that form part of ACS) and these costs are included in this estimated bill impact analysis. Other components of the electricity bill include wholesale electricity costs, retail costs and environmental policy costs. Figure 4 illustrates the different components of the electricity supply chain. Each of these costs contributes to the retail prices charged to customers by their chosen electricity retailer.

Figure 4 Electricity supply chain



Source: AER, *State of the Energy Market*, December 2018, p. 28.

For this final decision, we have estimated some indicative average distribution price impacts flowing from our allowed revenue determination. These prices are indicative and might vary with changes in demand.

Table 1 shows the estimated average annual impact of our final decision for the 2021–26 regulatory control period on electricity bills for residential and small business customers.

We estimate the expected impact on bills by varying the distribution charges in line with our 2021–26 final decision, while holding all other components constant. This approach isolates the effect of our final decision on distribution network tariffs from other parts of the bill. However, this does not mean that other components will remain unchanged across the regulatory control period.[16]

Under the final decision we estimate that compared to 2020 charges, the distribution network and metering charges ($ nominal) in CitiPower's area:

- for an average residential consumer would:
    - reduce by $46 (3.2 per cent) in the first year of the 2021–26 regulatory control period
    - increase on average by $1 (0.1 per cent) for each of the remaining four years of the 2021–26 regulatory control period.
- for an average small business consumer would:
    - reduce by $151 (2.6 per cent) in the first year of the 2021–26 regulatory control period
    - increase on average by $4 (0.1 per cent) for each of the remaining four years of the 2021–26 regulatory control period.

[16] It also assumes that actual energy consumption will equal the forecast adopted in our final decision. Since CitiPower operates under a revenue cap, changes in energy consumption will also affect annual electricity bills across the 2021–26 regulatory control period.

Table 1 Estimated contribution to annual electricity bills for the 2021–26 regulatory control period ($ nominal)

	2020	2021–22	2022–23	2023–24	2024–25	2025–26
AER Final decision						
Residential annual bill	1437[a]	1392	1393	1394	1396	1397
Annual change (per cent)[c]		–46 (–3.2%)	1 (0.1%)	1 (0.1%)	2 (0.1%)	2 (0.1%)
Standard control services		–27	1	1	1	1
Metering		–19	1	1	1	1
Small business annual bill	5894[b]	5743	5747	5751	5755	5759
Annual change (per cent)[c]		–151 (–2.6%)	4 (0.1%)	4 (0.1%)	4 (0.1%)	4 (0.1%)
Standard control services		–132	3	3	3	3
Metering		–19	1	1	1	1
CitiPower revised proposal						
Residential annual bill	1437[a]	1375	1380	1385	1390	1395
Annual change (per cent)[c]		–62 (–4.3%)	5 (0.3%)	5 (0.3%)	5 (0.4%)	5 (0.4%)
Standard control services		–41	4	4	4	4
Metering		–21	1	1	1	1
Small business annual bill	5894[b]	5671	5691	5713	5734	5756
Annual change (per cent)[c]		–223 (–3.8%)	21 (0.4%)	21 (0.4%)	21 (0.4%)	22 (0.4%)
Standard control services		–202	20	20	21	21
Metering		–21	1	1	1	1

Source: AER analysis; Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 – Final decision*, 18 November 2019, p. 76.

(a) Annual bill for 2020 is sourced from Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 – Final decision* and reflects the average consumption of 4000 kWh for residential customers in Victoria. This is then indexed by CPI for the half year period from 1 January 2021 to 30 June 2021 to allow comparison of the bill impact from 1 July 2021 onwards.

(b) Annual bill for 2020 is sourced from Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 – Final decision* and reflects the average consumption of 20000 kWh for small business customers in Victoria. This is then indexed by CPI for the half year period from 1 January 2021 to 30 June 2021 to allow comparison of the bill impact from 1 July 2021 onwards.

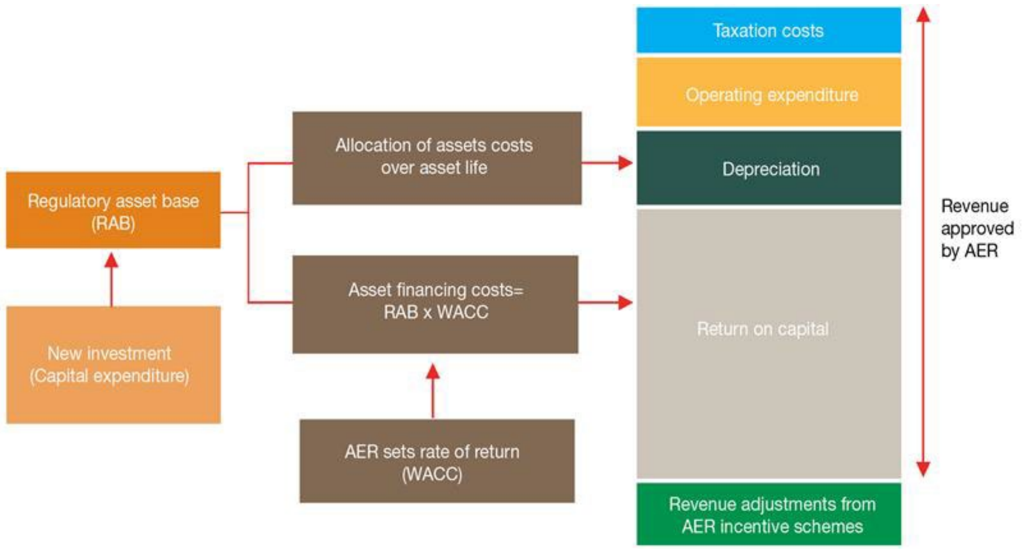
(c) Annual change amounts and percentages are indicative. They are derived by varying the distribution component of the 2020 bill amounts in proportion to yearly expected revenue divided by forecast energy as provided by CitiPower. Actual bill impacts will vary depending on electricity consumption and tariff class.

2 Key components of our final decision on revenue

The total revenue CitiPower proposed reflects its forecast of the efficient cost of providing its distribution network services over the 2021–26 regulatory control period. CitiPower's proposal, and our assessment of it under the National Electricity Law (NEL) and NER, are based on a 'building block' approach to determine a total revenue allowance which looks at six cost components:

- a return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in this business) (section 2.2)
- depreciation of the RAB (or return of capital, to return the initial investment to investors over time) (section 2.3)
- capex — the capital expenditure incurred in the provision of network services — mostly relates to assets with long lives, the cost of which are recovered over several regulatory control periods. The forecast capex approved in our decisions directly affects the projected size of the RAB and therefore the revenue generated from the return on capital and depreciation building blocks (section 2.4)
- forecast opex—the operating, maintenance and other non-capital expenses incurred in the provision of network services (section 2.5)
- the estimated cost of corporate income tax (section 2.6)
- revenue adjustments, including revenue increments or decrements resulting from the application of various incentive schemes (section 2.7).

Figure 5 The building block model to forecast network revenue



Source: AER, *State of the Energy Market*, December 2018, p.138.

We use an incentive approach where, once regulated, revenues are set for a five year period. Networks who keep actual costs below the regulatory forecast of costs retain part of the benefit. This incentive framework is a foundation of the regulatory framework, and is consistent with the National Electricity Objective (NEO). Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

Our final decision on CitiPower's distribution revenues for the 2021–26 regulatory control period is set out in Table 2.

Table 2 AER's final decision on CitiPower's revenues for the 2021–26 regulatory control period ($ million, nominal)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Return on capital	93.1	92.2	91.0	89.0	86.2	451.6
Regulatory depreciation[a]	70.6	77.0	84.2	90.9	96.9	419.7
Operating expenditure[b]	96.8	97.5	101.9	103.5	106.6	506.2
Revenue adjustments[c]	19.4	16.2	11.5	10.8	15.2	73.2
Cost of corporate income tax	8.2	7.4	6.1	7.2	7.4	36.3
Annual revenue requirement (unsmoothed)	288.1	290.4	294.8	301.4	312.3	1487.0
Annual expected revenue (smoothed)	**291.4**	**294.2**	**297.1**	**300.0**	**303.0**	**1485.8**
X factor[d]	n/a[e]	1.00%	1.00%	1.00%	1.00%	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening regulatory asset base (RAB).

(b) Includes debt raising costs.

(c) Includes revenue adjustments from the efficiency benefit sharing scheme (EBSS), the capital expenditure sharing scheme (CESS), shared assets adjustments and the demand management innovation allowance mechanism (DMIAM).

(d) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(e) CitiPower is not required to apply an X factor for 2021–22 because we set the 2021–22 expected revenue in this decision. The expected revenue for 2021–22 is around 10.3 per cent lower than the approved total annual revenue for 2020 in real terms, or 8.5 per cent lower in nominal terms after taking into account the escalation by half year Consumer Price Index (CPI) to allow comparison of the revenue from 1 July 2021 onwards.

Our final decision allows CitiPower to smooth its recovery of under-recovered distribution revenues in 2020 due to significantly reduced electricity consumption caused by the COVID-19 pandemic. These amounts are not included in our final decision annual revenue requirement for CitiPower. The total amount to be smoothed will be determined in CitiPower's 2021–22 pricing proposal and recovered in equal amounts over the remaining four years of the regulatory control period (2022–26) to reduce price impacts for customers. We consider that in exceptional circumstances deferrals or smoothing of revenue recovery can be allowed, taking into account the impacts to both the distributors and, importantly, customers. This is further discussed in attachment 14.

2.1 Regulatory asset base

The RAB is the value of assets used by CitiPower to provide regulated distribution services. The value of the RAB substantially impacts CitiPower's revenue requirement, and the price consumers ultimately pay. This makes it a key issue for many stakeholders. Other things being equal, a higher RAB would increase both the return on capital and depreciation (return of capital) components of the revenue determination.

As part of our decision on CitiPower's revenue for 2021–26, we make a decision on CitiPower's opening RAB as at 1 July 2021. We use the RAB at the start of each regulatory year to determine the return of capital (regulatory depreciation) and return on capital building block.

Our final decision is to determine an opening RAB value of $1968.9 million ($ nominal) as at 1 July 2021 for CitiPower. This amount is $11.0 million (or 0.6 per cent) lower than CitiPower's revised proposed opening RAB of $1979.9 million ($ nominal) as at 1 July 2021.[17] While we largely accept the proposed methodology for calculating the opening RAB, we made the following revisions to CitiPower's proposed inputs to the roll forward model (RFM):

- amended the 2020 capex estimate, which was provided by CitiPower subsequent to the revised proposal.
- amended inputs for the six month period of 1 January to 30 June 2021 (the six month 2021 period) for the nominal rate of return and equity raising costs.

To determine the opening RAB as at 1 July 2021, we have rolled forward the RAB over the 2016–20 regulatory control period and a further roll forward for the six month 2021 period[18] to arrive at a closing RAB value at 30 June 2021 in accordance with our RFM. This roll forward includes an adjustment at the end of the 2016–20 regulatory control period to account for the difference between actual 2015 capex and the estimate approved in the 2016–20 determination.[19] All other end of period adjustments are applied at 30 June 2021 to establish the opening RAB value at 1 July 2021.[20]

Table 3 sets out the roll forward of the RAB to the end of the 2016–21 period.

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17 CitiPower, *CP Revised regulatory proposal 2021–26*, 3 December 2020, pp. 55–56.

18 The additional roll forward for six months is due to the decision by the Victorian government to change the timing of the annual Victorian electricity network price changes to financial year basis from calendar year basis. This change means the current regulatory control period of 2016–20 is extended by six months and the next regulatory control period will commence on 1 July 2021.

19 The adjustment will be positive (negative) if actual capex is higher (lower) than the estimate approved at the 2016–20 determination.

20 These end of period adjustments are applied at the end of the final year of the roll forward period which in this case is 30 June 2021. For CitiPower this includes reallocation for accelerated depreciation purposes associated with solar enablement distribution transformers.

Table 3 AER's final decision on CitiPower's RAB for 2016–21 period ($ million, nominal)

	2016	2017	2018	2019	2020[a]	2021[b]
Opening RAB	1762.9	1813.6	1820.0	1849.3	1879.9	1929.8
Capital expenditure[c]	126.2	90.7	103.9	108.4	143.3	68.6
Inflation indexation on opening RAB	26.6	18.6	35.2	38.4	29.9	23.5
Less: straight-line depreciation[d]	102.1	102.9	109.9	116.2	122.7	53.1
Interim closing RAB	1813.6	1820.0	1849.3	1879.9	1930.4	1968.9
Difference between estimated and actual capex in 2015					–0.5	
Return on difference for 2015 capex					–0.1	
Closing RAB as at 31 December 2020					1929.8	
Opening RAB as at 1 July 2021						**1968.9**

Source: AER analysis.

(a) Based on estimated capex provided by CitiPower. We will true-up the RAB for actual capex at the next reset.

(b) The six month 2021 period of 1 January to 30 June 2021. Based on estimated capex provided by CitiPower. We expect to update the RAB roll forward with a revised capex estimate in the final decision, and true-up the RAB for actual capex at the next reset.

(c) Net of disposals and capital contributions, and adjusted for actual CPI and half-year WACC.

(d) Adjusted for actual CPI. Based on forecast capex.

Note: Summation of entries may not equal totals due to rounding.

For this final decision, we determine a forecast closing RAB value at 30 June 2026 of $2183.0 million ($ nominal) for CitiPower. This is $93.6 million (or 4.1 per cent) lower than CitiPower's revised proposal of $2276.5 million ($ nominal). Our final decision on the forecast closing RAB reflects the amended opening RAB as at 1 July 2021, and our final decisions on the expected inflation rate (attachment 3), forecast depreciation (attachment 4) and forecast capex (attachment 5).[21]

Table 4 sets out our final decision on the forecast RAB values for CitiPower over the 2021–26 regulatory control period.

[21] Capex enters the RAB net of forecast disposals. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Therefore, our final decision on the forecast RAB also reflects our amendments to the rate of return for the 2021–26 regulatory control period (section 2.2 of the Overview).

Table 4 AER's final decision on CitiPower's RAB for the 2021–26 regulatory control period ($ million, nominal)

	2021–22	2022–23	2023–24	2024–25	2025–26
Opening RAB	1968.9	2032.1	2091.0	2137.3	2167.4
Capital expenditure[a]	133.8	135.9	130.6	121.0	112.5
Inflation indexation on opening RAB	39.4	40.6	41.8	42.7	43.3
Less: straight-line depreciation	110.0	117.7	126.0	133.6	140.3
Closing RAB	**2032.1**	**2091.0**	**2137.3**	**2167.4**	**2183.0**

Source: AER analysis.

(a) Net of forecast disposals and capital contributions. In accordance with the timing assumptions of the post-tax revenue model (PTRM), the capex includes a half-year WACC allowance to compensate for the six-month period before capex is added to the RAB for revenue modelling.

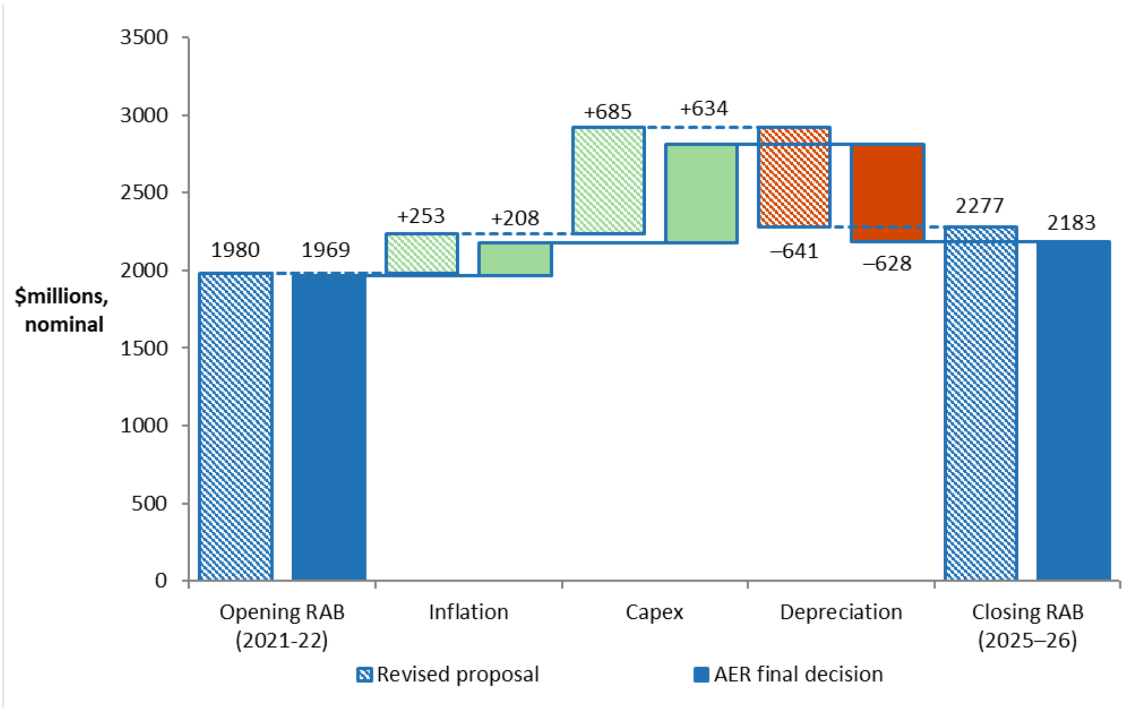
We are satisfied that the use of a forecast depreciation approach in combination with the application of the CESS and our other ex post capex measures are consistent with the capex incentive objective.[22] Further, this approach is consistent with our draft decision, CitiPower's revised proposal and our Framework and Approach.[23]

Figure 6 shows the key drivers of the change in CitiPower's RAB over the 2021–26 regulatory control period for this final decision. Overall, the closing RAB at the end of the 2021–26 regulatory control period is forecast to be 10.9 per cent higher than the opening RAB at the start of that period, in nominal terms. The approved forecast net capex increases the RAB by 32.2 per cent, while expected inflation increases it by 10.6 per cent. Forecast depreciation, on the other hand, reduces the RAB by 31.9 per cent.

22 Our ex post capex measures are set out in the capex incentive guideline, AER, *Capital expenditure incentive guideline for electricity network service providers,* November 2013, pp. 13–19 and 20–21. The guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective.

23 AER, *Draft decision: CitiPower distribution determination 2021 to 2026, Attachment 2 – Regulatory Asset Base*, September 2020, p. 18; CitiPower, *CP Revised regulatory proposal 2021–26*, 3 December 2020, p. 61; AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy – Regulatory control period commencing 1 January 2021,* January 2019, pp. 83–85.

Figure 6 CitiPower's actual, revised proposed and AER final decision RAB ($ million, nominal)



Source: AER analysis.

Note: Capex is net of forecast disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the PTRM.

Further detail on our final decision regarding the RAB is set out in attachment 2.

2.2 Rate of return and value of imputation credits

The return each business is to receive on its RAB (the 'return on capital') is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB. We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt.

The allowed rate of return provides the business with a return on capital to service the interest on its loans and give a return on equity to investors. An accurate estimate of the rate of return is necessary to promote efficient prices in the long-term interests of consumers.

We are required by the NEL to apply a rate of return instrument—the current 2018 Rate of Return Instrument (2018 Instrument)—to estimate an allowed rate of return.[24]

The Victorian Government moved the Victorian distributors from a calendar year regulatory control period to a financial year regulatory control period. [25] This entailed a six month extension to the current regulatory control period (2016–20) through to

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[24] NEL, Part 3, division 1B. AER, *Rate of return instrument*, December 2018, available at https://www.aer.gov.au/networks-pipelines/guidelinesschemes-models-reviews/rate-of-return-guideline-2018/final-decision.

[25] NELA Act.

June 2021 then a five year regulatory control period starting on 1 July 2021.[26] Our 2018 Instrument also needed to be applied from 1 January 2021—that is, to the six month extension period as well as the following five financial years which form the 2021–26 regulatory control period. Some amendments to the 2018 Instrument were needed to accommodate the additional six month period. The Victorian government enabled these amendments through the NELA Act.[27] Therefore, we apply a modified 2018 Instruments to both periods.[28][29]

Application of a modified 2018 Instrument in this final decision estimates an allowed rate of return of 4.73 per cent (nominal vanilla) for the five year regulatory control period commencing 1 July 2021. We note CitiPower's proposal and revised proposal also applied of these modifications to the 2018 Instrument.[30]

Our calculated rate of return (in Table 5) will apply to the first year of the 2021–26 regulatory control period. A different rate of return will apply for the remaining regulatory years of the period. This is because we will update the return on debt component of the rate of return each year in accordance with a modified 2018 Instrument, which uses a 10-year trailing average portfolio return on debt that is rolled-forward each year.

Table 5 AER's final decision on CitiPower's rate of return (nominal)

	AER draft decision (2021–26)	CitiPower's revised proposal (2021–26)	AER final decision (2021–26)	Allowed return over regulatory control period
Nominal risk free rate	0.93%[a]	0.93%	1.38%[c]	
Market risk premium	6.1%	6.1%	6.1%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post–tax)	4.59%	4.59%	5.04%	Constant (%)
Return on debt (nominal pre–tax)	4.59%[b]	4.59%	4.52%[d]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	4.59%	4.59%	4.73%	Updated annually for return on debt
Expected inflation	2.37%	2.37%	2.00%	Constant (%)

26 The 6 month extension period was also labelled as the 'mini-year' when we consulted on the modifications to the 2018 Rate of Return Instrument.

27 *NELA Act*.

28 *NELA Act*.

29 For the 6 month extension period instrument see: AER, *Modified rate of return instrument for the Victorian electricity distribution networks during the extension period of 1 January 2021 to 30 June 2021*, 27 October 2020; For the instrument to apply to the 2021–26 regulatory control period , see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).

30 CitiPower, *Regulatory Proposal 2021–26*, January 2020, p. 125; CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 58.

Source: AER analysis; CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 58; CitiPower, *Revised regulatory proposal 2021–26, MOD 10.02, PTRM 2021–26*, December 2020.

[a,b] Calculated using a placeholder averaging period.

[c,] Calculated using an averaging period of 2 January 2021 to 29 March 2021.

[d] Final decision return on debt is calculated using the proposed and accepted debt averaging period.

Our final decision is also to accept CitiPower's proposed risk free rate averaging period[31] and debt averaging periods because they comply with conditions in a modified 2018 Instrument.[32] These were submitted with its initial regulatory proposal and we specify the debt averaging periods in confidential appendix A to attachment 3.

Debt and equity raising costs

In addition to providing for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs. We include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments.

We note CitiPower has proposed to use our approach to estimate equity raising costs.[33] We have updated our estimate for this regulatory control period based on the benchmark approach using updated inputs. This results in equity raising costs of $1.78 million.

Our final decision is to accept the method used in CitiPower's revised proposal which uses an annual rate of 8.1 basis points per annum.[34] We have considered this annual rate and found our alternative benchmark estimate (8.1 basis points) is similar to CitiPower's proposal

Imputation credits

Our final decision is to apply a gamma of 0.585 as provided in a modified 2018 Instrument.[35] CitiPower's revised proposal has adopted a value of 0.585.[36]

Inflation

We estimate an expected inflation of 2.0 per cent based on the approach adopted in our final position paper from our 2020 inflation review.[37] CitiPower accepted the

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31 This is also known as the return on equity averaging period.

32 For the financial year regulatory control period instrument, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).; see also AER, *Final decision, CitiPower distribution determination 2021 to 2026, Attachment 3—Rate of return confidential appendix A: Equity and debt averaging periods*, April 2021.

33 CitiPower, *Revised regulatory proposal - 2021–26, MOD10.02, PTRM 2021–26*, December 2020.

34 CitiPower, *Revised regulatory proposal - 2021–26, MOD10.02, PTRM 2021–26*, December 2020.

35 For the modified application of the 2018 instrument to the regulatory control period 2021–26, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).

36 CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 59.

37 See our latest version of the PTRM (version 5) released in April 2021; AER, *Final position, Regulatory treatment of inflation*, December 2020.

inflation rate in the draft decision but expected the value to be updated for the outcome of the inflation review.[38]

True up for six month extension period

We applied placeholder averaging periods in our final decision for the six month extension period of 1 January 2021 to 30 June 2021.[39] This was because of the unanticipated delay in the passing of the NELA Act, and to facilitate our pricing process – the nominated (and accepted) averaging periods would not have finished in time to allow practical estimation of the final rate of return (based on the accepted averaging periods).

We have calculated the updated rate of return for the extension period based on the nominated and accepted averaging periods, and in accordance with the modified six-month instrument and the Order in Council. We determine that the difference with the placeholder rate of return will be recovered through the C-factor as noted in our control mechanisms attachment.

2.3 Regulatory depreciation (return of capital)

Depreciation is the amount provided so capital investors recover their investment over the economic life of the asset (return of capital). CitiPower invests capital in large assets to provide electricity network services to its consumers. The costs of these assets are recovered over the asset's useful life, which in many cases can be 50 or more years. This means only a small part of the cost of such assets are recovered from consumers upfront or in any year. The greater proportion is recovered over time through the depreciation allowance.

In deciding whether to approve the depreciation schedules submitted by CitiPower, we make determinations on the indexation of the RAB and depreciation building blocks for CitiPower's 2021–26 regulatory control period.[40] The regulatory depreciation amount is the net total of the straight-line depreciation less the indexation of the RAB.

Our final decision is to determine a regulatory depreciation amount of $419.7 million ($ nominal) for CitiPower for the 2021–26 regulatory control period. This amount represents an increase of $31.4 million (or 8.1 per cent) to the $388.3 million ($ nominal) in CitiPower's revised proposal.[41] It is $35.6 million (or 9.3 per cent) higher than the regulatory depreciation amount determined in the draft decision. This significant increase is driven by our review of lower expected inflation which resulted from our inflation review. This lower expected inflation (amongst other things) impacts the indexation component of the regulatory depreciation allowance.

In coming to this decision:

- We accept CitiPower's revised proposed straight-line method to calculate the regulatory depreciation, which is consistent with our draft decision.

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[38] CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 56.

[39] For example, see: AER, *Final decision CitiPower six-month extension – variation decision*, October 2020, pp. 11–12.

[40] National Energy Rules (NER), cll. 6.12.1, 6.4.3.

[41] CitiPower, *Revised regulatory proposal 2021–26 MOD 10.02 - PTRM 2021–26,* updated 22 December 2020.

- We accept CitiPower's revised proposal to continue with the year-by-year tracking approach to implement straight-line depreciation of existing assets, consistent with our draft decision. However, we have updated the inputs in the depreciation model for 2020 capex and the forecast equity raising costs and nominal rate of return inputs for the six month period of 1 January to 30 June 2021 (the six month 2021 period), consistent with the RFM.
- We accept CitiPower's revised proposed asset classes and standard asset lives, which are consistent with our draft decision. We have updated the equity raising costs standard asset life using our standard weighted average approach.
- We accept CitiPower's revised proposed reallocation of $1.0 million of existing assets into its new asset class of 'Accelerated depreciation assets' from the 'Distribution system assets' class. This amount is consistent with our draft decision.

The difference in our final decision and the revised proposed regulatory depreciation allowance is largely due to the following determinations on related parts of our decision:

- expected inflation over the 2021–26 regulatory control period (attachment 3)
- forecast capex (attachment 5) including its effect on the projected RAB over the 2021–26 regulatory control period.[42]

Further detail on our final decision regarding depreciation is set out in attachment 4.

2.4 Capital expenditure

Capex refers to the investment in assets to provide network services. This investment mostly relates to assets with long lives and these costs are recovered over several regulatory periods. Capex is added to CitiPower's RAB, which is used to determine the return on capital and return of capital (regulatory depreciation) building block allowances. All else being equal, higher forecast capex will lead to a higher projected RAB value and higher return on capital and regulatory depreciation allowances.

Our final decision on CitiPower's total net capex is to not accept its revised proposal of $633.3 million ($2020–21) for the 2021–26 regulatory control period. We are not satisfied that CitiPower's revised total capex proposal reasonably reflects prudent and efficient costs. Our final decision includes a total capex forecast of $589.9 million ($2020–21). This is 7 per cent below CitiPower's revised forecast.

CitiPower accepted several aspects of our draft decision, materially reducing its forecast capex by 25 per cent relative to its initial proposal. Figure 7 compares our total capex final decision, with its initial and revised proposal as well as its current period spend. While we acknowledge CitiPower's efforts to reconsider its forecast in light of our concerns about its initial proposal in our draft decision, we would encourage them and other distributors to include in the initial proposal, more substantiated capital expenditure requirements. We note that its initial forecast assessed was 41 per cent

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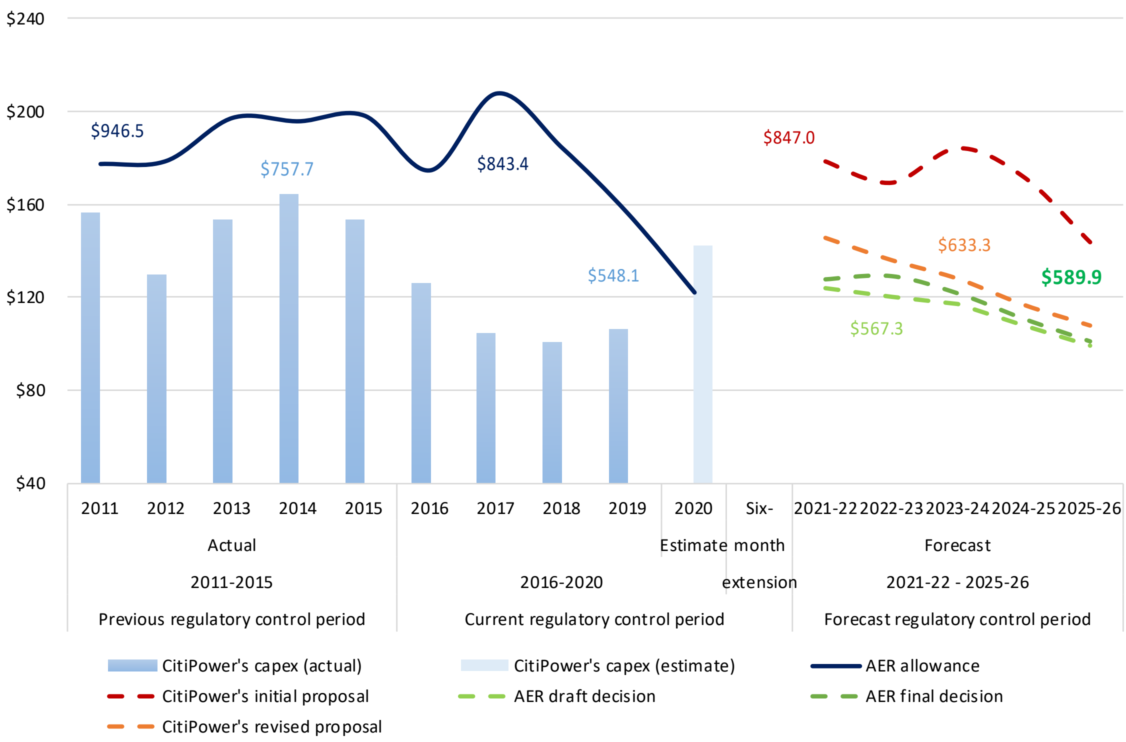
42 Capex enters the RAB net of forecast disposals and capital contributions. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Our final decision on the RAB (Attachment 2) also reflects our updates to the WACC for the 2021–26 regulatory control period.

above current period actual spend,[43] with insufficient evidence to support its forecast in full. For the AER to be satisfied that a distributors forecast reasonably reflects efficient and prudent costs, we expect initial proposals to be supported by quantitative business cases as well as reflect genuine engagement with its customer base.

Figure 7 CitiPower's historical vs forecast capex snapshot ($ million, 2020–21)



Source: AER analysis

In coming to our final decision, we asked CitiPower questions on its revised proposal. CitiPower was receptive to our questions and provided responses within requested timeframes. Our final decision is higher than our draft decision as CitiPower provided sufficient evidence to satisfy us that parts of its revised forecast is prudent and efficient.

Our final decision provides a capex allowance that is 8 per cent above CitiPower's current period spend. We are satisfied that this capex allowance is sufficient for CitiPower to maintain its services level given that it has performed well on a number of network health indicators over the current period. Our decision does not preclude CitiPower from changing the mix of capex projects and programs it has proposed for this review or from spending more than its capex allowance. Our regulatory framework recognises that circumstances may change over the course of the regulatory control period and that a distributor may need to reallocate capex to manage its risks.

[43] This comparison considers expenditure for minor repairs as opex for both the forecast assessed and the current period spend.

Overall, we note the following:

- On repex, while in some cases we were satisfied that sufficient evidence was provided to demonstrate its forecast was prudent and efficient, we were not satisfied in others. For instance, we have accepted CitiPower's forecast for its circuit breaker program, but not accepted its revised proposal for CBD pits and wood poles.
- For its wood pole forecast, we were not satisfied that there is likely to be a change in network risk over the forecast period to justify a 115 cent forecasted step up relative to its current period spend. We especially note that CitiPower's proposal was overwhelmingly focused on Powercor's network requirements, and given the different characteristics and performances of the networks, we are not satisfied that this forecasting approach results in prudent and efficient poles repex.
- The Consumer Challenge Panel, sub-panel 17 (CCP17) supported our draft decision, and questioned aspects of CitiPower's revised regulatory proposal.[44] Similarly, the Victorian Community Organisations (VCO) considered the draft determinations addressed stakeholder concerns about a continually-growing RAB, whereas the revised proposals for capex are likely to exceed requirements.[45]

Further detail on our final decision regarding capex is set out in attachment 5.

2.5 Operating expenditure

Opex is the forecast of operating, maintenance and other non-capital costs incurred in the provision of prescribed distribution standard control services. Forecast opex is one of the building blocks we use to determine CitiPower's total regulated revenue requirement.

Our final decision is to accept CitiPower's total opex forecast of $476.7 million, including debt raising costs, for the 2021–26 regulatory control period. This is because our alternative estimate of $473.7 million is not materially different than CitiPower's updated revised total opex forecast proposal. Therefore, we consider that CitiPower's total opex forecast reasonably reflects the opex criteria.[46]

Figure 8 shows CitiPower's opex forecast for the next 5 years, which is increasing by $76.3 million or 19.0 per cent relative to its actual (and estimated) opex in the current regulatory control period.

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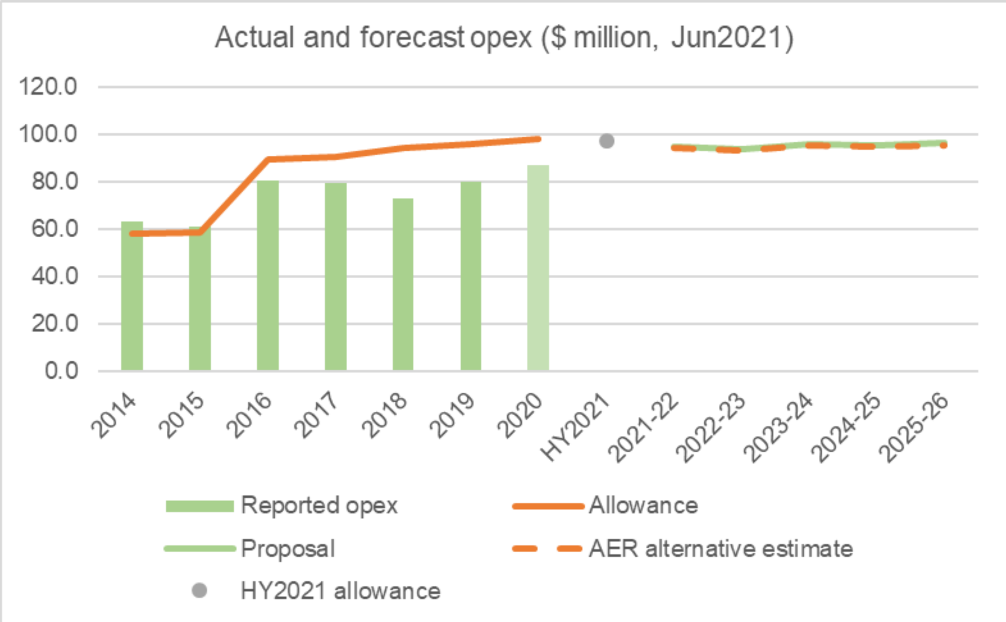
[44] CCP17, *Submission on the Victorian EDPR Revised Proposal and Draft Decision 2021–26,* January 2021, p.108-110

[45] VCO, *Submission on the Victorian EDPR revised proposals and draft decision 2021–26*, January 2021, p.6

[46] NER, cl.6.5.6(c).

Figure 8 CitiPower's opex over time ($ million, 2020–21)



Source: CitiPower, *Revised Regulatory Proposal 2021–26 - MOD 10.06 - Opex - 20201221 update*, December 2020; AER, *Final Decision, CitiPower distribution determination 2021–26, Opex model*, April 2021; AER, *Final Decision, CitiPower distribution determination 2021–26, EBSS model*, April 2021; AER analysis.

We applied, (as did CitiPower) our top-down base-step-trend approach to forecast increasing opex for the 2021–26 regulatory control period. This consists of:

- Starting with reported opex in 2019 as the opex base, which is lower than the forecast we set for the current regulatory control period, and we consider is reasonable as it is not materially inefficient.
- Escalating base opex to account for forecast changes in price growth, output growth and productivity over the next regulatory control period, which we consider is reasonable and consistent with our standard approach.
- Adding a number of base adjustments, step changes and category specific forecasts. These increases include costs to meet new obligations or capex / opex trade-offs such as those for security of critical infrastructure, five minute meter requirements, IT cloud, solar enablement, Yarra Trams pole relocation works and the reclassification of categories of repair works from capex to opex. We have assessed these and consider they are prudent and efficient. These additions are a key driver for forecast opex being higher than historical levels.

We have set out the reasons for our final decision on opex in more detail in attachment 6. Our opex model, which calculates our alternative estimate of opex, is available on our website.

2.6 Corporate income tax

Our final decision on CitiPower's estimated cost of corporate income tax is $36.3 million over the 2021–26 regulatory control period. This represents an increase of $12.6 million (or 53.1 per cent) from CitiPower's revised proposed cost of corporate income tax of $23.7 million ($ nominal). The key reasons for this change are:

- Our final decision to reduce the immediately expensed capex for tax purposes from $255.4 million to $226.8 million ($2020–21).[47]
- Our final decision to increase the regulatory depreciation (attachment 4).[48]
- Our final decision to apply an updated rate of return on equity (attachment 3).[49]
- Our final decision to reduce the revised proposed opening tax asset base (TAB) value as at 1 July 2021 by $11.6 million to $1766.3 million.[50]

We accept CitiPower's revised proposal on the standard tax asset lives for all of its asset classes, consistent with our draft decision. We have updated CitiPower's remaining tax asset lives as at 1 July 2021 to reflect our amendments to the opening TAB value.

We also accept CitiPower's revised proposal for changing the tax treatment of gifted assets. The change in approach is consistent with a recent ruling by the Full Federal Court of Australia[51] made after the draft decision.

Further detail on our final decision on corporate income tax is set out in attachment 7.

2.7 Revenue adjustments

Our final decision on CitiPower's total revenue also includes a number of adjustments:

- **Efficiency benefit sharing scheme (EBSS**) – we have calculated CitiPower accrued EBSS carryovers totalling $0.4 million ($2020–21) from the application of the EBSS in the 2016–20 period. This is the same carryover amount CitiPower included in its revised proposal. The EBSS is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and network users. Consumers benefit from improved efficiencies through lower forecast opex in subsequent periods. Attachment 8 sets out our final decision on CitiPower's EBSS.
- **CESS** – CitiPower has accrued rewards under the CESS we applied in the current 2016–20 regulatory control period to incentivise CitiPower to undertake efficient capex throughout the period. The CESS rewards efficiency gains and penalises efficiency losses, each measured by reference to the difference between forecast and actual capex. In the 2016–20 period, CitiPower out-performed our capex forecast, and our final decision is to approve a CESS revenue increment amount of $68.3 million ($2020–21). This amount is higher than our draft decision forecast of $63.8 as it reflects updated Consumer Price Index, weighted average cost of capital and actual capex.

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[47] All else equal, a lower immediately expensed capex amount will increase the cost of corporate income tax because it reduces the tax expense.

[48] All else equal, a higher regulatory depreciation amount will increase the cost of corporate income tax because it increases the taxable income.

[49] All else equal, a higher rate of return on equity will increase the cost of corporate income tax because it reduces the return on equity, a component of the taxable income.

[50] All else equal, a higher opening TAB value will increase the tax depreciation, a component of the tax expense, and lower the cost of corporate income tax.

[51] Federal Court of Australia, *Victoria Power Networks Pty Ltd v Commissioner of Taxation [2020] FCAFC 169*, 21 October 2020.

- **Shared assets** — Distributors, such as CitiPower, may use assets to provide both the SCS we regulate, and unregulated services. These assets are called 'shared assets'. If the revenue from shared assets is material, ten per cent of the unregulated revenues that a distributor earns from shared assets will be used to reduce the distributor's revenue for SCS. For this final decision, we determine a revenue adjustment of $1.5 million ($2020–21) to be shared with customers across the 2021–26 regulatory control period.
- **Demand management innovation allowance mechanism (DMIAM)** —Table 6 sets out the DMIAM allowance for CitiPower for the 2021–26 regulatory control period, based on the final PTRM for CitiPower. The DMIAM aims to encourage distribution businesses to find investments that are lower cost alternatives to investing in network solutions.

Table 6 AER's final decision on the DMIAM ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
DMIAM	0.43	0.43	0.44	0.44	0.45	2.18

Source: AER analysis.

Section 4 sets out our final decision on the incentive schemes that apply to CitiPower over the next regulatory control period.

3 CitiPower's consumer engagement

A significant development in the preparation of proposals for the Victorian Electricity Distribution 2021–26 regulatory control period, has been the improvement in consumer engagement approaches undertaken by the distributors. Stakeholders have commented favourably on the observed improvement in consumer engagement across all Victorian distributors.[52] As a result of this advancement, we developed a framework[53] for assessing the Victorian distributor's consumer engagement activities, which we published in our draft decision.[54]

The framework sought to provide increased transparency around our assessment of consumer engagement outcomes and how this has influenced our decisions on expenditure forecasts. It was developed, based on our observations on the quality of engagement, to represent a range of considerations we thought clearly demonstrated if consumers had been genuinely engaged during development of proposals.[55] The framework, in its current form, represents a high threshold a distributor would need to meet – among other things – should it be seeking to submit a proposal that is 'capable of acceptance'. Used in conjunction with our technical analysis, the framework allowed us to place weight on the outcomes of the engagement activities undertaken by each distributor to assist in providing an overall assessment of expenditure proposals. In response to a number of submissions[56], this final decision also provides further clarity on the use of the framework in our decision-making process. Noting that while we take the quality of consumer engagement, and the extent to which proposals are influenced by consumer preferences into account, it does not displace our technical assessment under the NER. The assessment of consumer engagement under the framework can however, inform the depth of technical assessment required.

Stakeholder submissions on our draft decision supported the framework,[57] as a tool in our kit, along with the further development of our approach to consumer engagement.[58] We also recognise there may be other elements of engagement which are also worthy of inclusion as our assessment approach develops.[59] As a result, we

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52 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp 6-42.; CCP17, *Submission on the Victorian Electricity Distribution Regulatory Proposal 2021–26*, June 2020, p.10.; Department of Environment, Land, Water and Planning, *Victorian Government submission on the electricity distribution price review 2021–26*, May 2020, p. 2;, EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 2.; ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 6.

53 Table 7: AER, *Draft decision, CitiPower distribution determination 2021-26, Overview - September 2020*, p. 41.

54 AER, *Draft decision, AusNet Services distribution determination 2021-26, Overview - September 2020*, p. 41..

55 AER, *Draft decision, AusNet Services distribution determination 2021-26, Overview - September 2020*, p. 40.

56 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 7.; VCO, *Submission on the Victorian Electricity Distribution Regulatory Proposal 2021–26*, June 2020, p. 12; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 12, 14.

57 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 2, 3-4, CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 6-42; ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 8.; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 12.

58 Op cit.

59 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 6-42; EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 3-4.; ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 9.;

plan to take any further development of the framework in full consultation with stakeholders, outside of the Victorian reset process. However, to maintain consistency of our assessment of the Victorian distributor's consumer engagement in this final decision, we have continued with the approach outlined in our draft decision.

3.1 Clarifying the role of consumer engagement

Some stakeholders have expressed concern that an assessment of high quality consumer engagement may lead to a decreased level of technical assessment. In particular, the Energy Users Association of Australia (EUAA) and VCO submissions suggested that successful participation in a New Reg process could lead to a network business getting a 'rails run', with less detailed regulatory scrutiny.[60]

The NER outlines that we must have regard to consumer concerns, and be satisfied that expenditure forecasts we approve reasonably reflect prudent and efficient costs. One of the factors that we must have regard to is the extent to which the capex and opex forecasts address consumer concerns identified throughout a distributors' engagement with its customers.[61] However, this must be balanced against other capex and opex factors, including that we must have regard to distributors' actual and expected capex and opex in preceding regulatory periods[62], and whether the forecasts are consistent with any relevant incentive schemes.[63] In undertaking our reviews, we apply a number of bottom-up and top-down assessment techniques. Our technical analysis makes use of a range of measures, none of which are used deterministically in isolation. The quality of a distributor's consumer engagement informs the nature of our technical assessment but does not displace it.

3.2 Assessment of consumer engagement

In our assessment of consumer engagement, in the development of proposals for the 2021–26 regulatory control period, we recognise that each distributor has approached consumer engagement differently.

CitiPower, Powercor and United Energy worked together on a common strategy to engage with their customers in the development of regulatory proposals for the three networks. The initial proposal outlined its 'Energised 2021–26' program, which consulted on a broad range of topics, across a diverse cross-section of the combined customer base. While this approach was considered a major strength[64], in our draft decision we concluded that this engagement was not clearly reflected in how it influenced their proposals.[65] Our draft decisions noted that in addition to our top-down technical assessments, outcomes from CitiPower's consumer engagement process

CitiPower, Powercor and United Energy, Revised Regulatory Proposal - 2021-26 - December 2020, p. 26.; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 12-13.

60 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 1; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 12.

61 NER, cl. 6.5.7(e)(5A) and 6.5.6(e)(5A).

62 NER, cl. 6.5.7(e)(5) and 6.5.6(e)(5).

63 NER, cl. 6.5.7(e)(8) and 6.5.6(e)(8).

64 See VCO, *Submission on the Victorian EDPR revised proposals and draft decision 2021–26*, January 2021 – p 12 where they note that the CitiPower, Powercor and United Energy program was the most successful in testing priorities of different sectors within their base.

65 AER, *Draft Decision –CitiPower distribution determination 2021–26 Overview*, September 2020, p. 4.

was not sufficient to persuade us that a more thorough bottom-up analysis was not warranted. Further, that proposed expenditure forecasts should be accepted in the face of this bottom-up analysis.[66]

In response to our draft decision, we acknowledge that CitiPower, Powercor and United Energy have taken on board our comments and the feedback of stakeholders regarding their engagement. For example, CitiPower noted that while it believed its engagement had been 'broad and comprehensive' it also listened to stakeholder feedback to reshape its program to include a smaller panel, comprised of experienced members representing a cross-section of customers.[67] This led to the establishment of its CAP[68], which will also become part of its 'business as usual' engagement with customers.[69] The CAP delved into "marque programs" and topics of engagement with the intent to provide feedback on reducing the revised proposal spending in line with customer preferences by testing the programs through informed discussions.[70]

In providing this assessment, we recognise that the limited timeframe, between the draft decision and submission of the revised proposals presented challenges for distributors to address all elements of our framework.

We observe that CitiPower's engagement with its CAP appears genuine and the distributors used the panel's expertise in the revised proposal.[71] [72] A number of "marquee programs" that the CAP engaged on included; customer enablement, poles management and forecasting for COVID-19.[73] However, the CAP did not engage deeply on the total revised proposal package. The CCP17 noted this point, but concluded that while the CAP did not have an opportunity to review the revised proposals 'as a whole', they did not see it is a significant shortcoming.[74] In contrast, the VCO, noted in their submission that CitiPower, Powercor and United Energy were the most successful in engaging with 'different sectors within their base'.[75] The engagement of the CAP, can be seen as an important complementary function to the broad engagement already undertaken.

CitiPower has provided greater explanation in its revised proposal documents, including sign-post tables outlining the engagement undertaken since submission of its initial proposal. It also outlined the feedback received from stakeholders and how its engagement for the revised proposal had been more targeted, including collaboration

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66 AER, *Draft Decision –CitiPower distribution determination 2021–26 Overview*, September 2020, p. 47.

67 CitiPower, *Revised Regulatory Proposal - 2021–26*, December 2020, pp. 8, 14.

68 CitiPower, *Revised Regulatory Proposal - 2021–26*, December 2020, p. 12.

69 CitiPower, *Revised Regulatory Proposal - 2021–26*, December 2020, p. 14.

70 CitiPower, Powercor and United Energy have provided their CAP with detailed information packs to equip its members to allow for a deep and meaningful discussion. For an example see CitiPower's supporting attachments provided by their consultant Forethought Customer Engagement and CAP supporting documents.

71 CitiPower, *Revised Regulatory Proposal - 2021–26*, December 2020, p. 14.

72 CitiPower, *Revised Regulatory Proposal - 2021–26*, December 2020, p. 17: CAP member Dean Lombard, noted the openness of the engagement, with CitiPower, Powercor and United Energy 'sharing key Information and having frank discussions with members about the issues at hand and the alternative approaches to them..

73 See CitiPower, *Revised Regulatory Proposal - 2021–26 - Att 14 - CAP - Meeting 1 Minutes 2020, Att 20 - CAP - Meeting 2 Minutes, Att 27 - CAP - Meeting 3 Minutes 2020,* December 2020.

74 CCP17, *Submission on the Victorian EDPR Revised Proposal and Draft Decision 2021–26,* January 2021, p 3.

75 VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26 - January 2021*, p. 13.

with the CAP.[76] ECA's consultant, Spencer&Co, were satisfied that the revised proposals 'adequately linked customers views to the outcomes proposed'.[77] We acknowledge the improvement that CitiPower undertook to clearly identify the elements of its revised proposal that were shaped by discussions with its CAP. Given the limited timeframe, this may have contributed to the targeted discussions driven largely by CitiPower on its "marquee programs", which limited consumer's influence to other significant aspects of its revised proposal.

CitiPower's revised proposal largely accepted the main elements of our draft decision which are discussed further in Sections 2.4 (capex) and 2.5 (opex). The CCP17 were supportive of our reduction in the draft decision relating to the proposed capital investment by CitiPower.[78] They were also encouraged that CitiPower accepted most of the matters raised in the draft decision and acknowledged 'the removal of the forecast risk-driven pole intervention forecast', a position that was taken after consultation with their CAP, notably the meeting of 20 October 2020'.[79] As already discussed, we have not included this particular forecast into the total capex allowance.

CitiPower, Powercor and United Energy have acknowledged they are continuing to learn and improve their engagement approach.[80] We recognise the significant work undertaken following the draft decision with the initiative of the CAP however, there is still further work that can be done by CitiPower to demonstrate that its customers are consistently understood and considered in its decisions. Overall, while we have undertaken a more thorough bottom-up analysis of CitiPower's proposal, we are confident that the consumer engagement undertaken since our draft decision with the CAP demonstrates progress towards establishing the proof points set out in our framework.

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76 CCP17, *Submission on the Victorian EDPR Revised Proposal and Draft Decision 2021–26* -January 2021, p 42-43. See also CitiPower, *Revised Regulatory Proposal - 2021–26*, December 2020, pp.18-23.

77 ECA, Spencer&Co report - *Submission and attachment on the Victorian EDPR Revised Proposal and Draft Decision 2021–26*, 20 January 2021, p.6.

78 CCP17, *Submission on the Victorian EDPR Revised Proposal and Draft Decision 2021–26* -January 2021, p. 108.

79 Ibid, p. 108.

80 CitiPower, *Revised Regulatory Proposal 2021–26*, December 2020, p, 12.

4 Incentive schemes

Incentive schemes are a component of incentive based regulation and complement our approach to assessing efficient costs. These schemes provide important balancing incentives under the revenue determination we've discussed in section 2, to encourage CitiPower to pursue expenditure efficiencies and demand side alternatives while maintaining the reliability and overall performance of its network.

The incentive schemes that might apply to an electricity distribution network as part of our decision are:

- the opex EBSS
- the capital CESS
- the service target performance incentive scheme (STPIS)
- the customer service incentive scheme (CSIS)
- the demand management incentive scheme (DMIS) and allowance (DMIAM)
- the f-factor scheme.

Once we make our decision on CitiPower's revenue cap, it has an incentive to provide services at the lowest possible cost, because its returns are determined by its actual costs of providing services. Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. If a network reduces costs to below our forecast of efficient costs, the savings are shared with its consumers in future regulatory periods through a lower opex allowance and a lower RAB.

We understand the strong concerns of stakeholders that the CESS not only rewards efficiency gains but also over forecasting and deferral of capex. The current CESS guideline includes protections against material deferrals that have been triggered for some elements of Powercor's proposal[81] but not for CitiPower. Protection against over forecasting of capex lies in the rigorous assessment of proposed capex.

The DMIS and the DMIAM provide businesses an incentive to undertake efficient expenditure on non-network options relating to demand management research and development in demand management projects that have the potential to reduce long-term network costs. All Victorian distributors accepted our draft decision to apply this scheme. We acknowledge that the Local Government Response expressed its concern that the full DMIAM allowance has been approved for Jemena, CitiPower and Powercor, without justification or evidence of the types of activities that will be undertaken.[82]

While we acknowledge this concern, we consider that the DMIAM research and development works have the potential to deliver long-term savings to consumers. The scheme has an in-built control framework to ensure that only those expenditures that

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[81] AER, *Final Decision, Powercor Distribution Determination 2021–26, Attachment 9 Capital Expenditure Sharing Scheme*, April 2021.

[82] Local Government Response prepared by Victorian Greenhouse Alliances, *Submission to the Australian Energy Regulator (AER) Victorian Electricity Distribution Price Review (EDPR) 2021–26, Local Government Response to the AER's Draft Determination,* December 2020, p. 10.

meet the tests prescribed by the scheme will be approved. Any unspent DMIAM allowance will be returned to consumers.

Our final decision is to apply the DMIS[83] and the DMIAM[84] to CitiPower for the 2021–26 regulatory control period, without any modification. Our draft decision reasons form part of this final decision.

The STPIS is intended to balance incentives to reduce expenditure with the need to maintain or improve service quality. Our final decision is to apply our national STPIS version 2.0 (November 2018) to CitiPower for the 2021–26 regulatory control period. We will not apply the GSL component to CitiPower as the existing jurisdictional arrangements will continue to apply. We will not apply the STPIS telephone answering target and incentive rate to CitiPower in the next regulatory control period because we have accepted the distributor's proposal for a CSIS made in its revised proposal. However, CitiPower should continue to report on the telephone answering parameter in the next regulatory control period. Attachment 10 sets out our final decision on CitiPower's STPIS.

Our final decision is to apply CitiPower, Powercor and United Energy's proposed CSIS design. The proposed scheme replaces the current STPIS telephone answering parameter with a more holistic incentive that addresses its customer's preferences, as identified through a genuine and thorough engagement process. The performance targets are based on historical performance, with the revised revenue adjustment formula ensuring that incentives and penalties are commensurate to the value identified by customers. The scheme has been approved by CitiPower, Powercor, United Energy's CAP, and external stakeholders have also expressed support for the scheme in submissions. For each businesses, we the total revenue at risk for customer service performance will be 0.5 per cent of total revenue.

Our final decision is that each of the EBSS, CESS, STPIS, CSIS, DMIS and DMIAM should apply to CitiPower for the 2021–26 regulatory control period.

Our final decision also includes how the f-factor scheme is applied to CitiPower in the 2021–26 regulatory control period. The f-factor scheme is prescribed by the Victorian Government's F-Factor Scheme Order 2016 to reduce the risk of fire starts by network assets[85]. The 2016 Order was amended by the F-factor Scheme Amendment Order 2020. We have made an f-factor scheme determination for CitiPower under the F-Factor Scheme Order in respect of the 2021–26 regulatory control period, as detailed in attachment A of our draft decision. Our final decision is to make revenue adjustments for CitiPower in accordance with the F-Factor Scheme Order by way of an annual adjustment through the "I-factor" component in the control mechanism, as specified in attachment 14 of the final decision.

We discuss our final decisions on each incentive scheme in attachments 8 to 12.

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83 AER, *Demand management incentive scheme*, *Electricity distribution network service providers*, December 2017.

84 AER, *Demand management innovation allowance mechanism*, *Electricity distribution network service providers*, December 2017.

85 http://www.gazette.vic.gov.au/gazette/Gazettes2016/GG2016G051.pdf.

5 Tariff structure statement

CitiPower's 2021–26 proposal includes the second iteration of its tariff structure statement (TSS). Its current TSS applies from 1 January 2016 to 30 June 2021.[86]

The requirement on distributors to prepare a TSS arises from significant reforms to the rules governing distribution network pricing. These reforms aim to:

- help distributors provide better price signals to retailers to reflect what it costs to use the network
- manage future expectations for retailers, distributors and consumers by providing guidance on distributors' tariff strategy
- help the transition to more cost reflecting pricing.

Distributors do not directly charge end customers. Rather, distributors charge retailers for the network services provided to end customers. Retailers can then decide how best to pass on these price signals to end customers.

A TSS applies to a distributor's tariffs for the duration of the regulatory control period. It describes a distributor's tariff classes and structures, the distributor's policies and procedures for assigning and reassigning customers to tariffs, the charging parameters for each tariff, and a description of the approach the distributor takes to setting tariffs in pricing proposals.[87] It is accompanied by an indicative pricing schedule.[88] A TSS provides consumers and retailers with certainty and transparency in relation to how and when network prices will change.

While an indicative pricing schedule must accompany the TSS, CitiPower's tariffs for the entire 2021–26 regulatory control period are not set as part of this determination. Rather, tariffs for 2021–22 will be subject to a separate approval process that takes place in May 2021, after this final revenue determination in April 2021. Tariffs for the following four years will also be approved on an annual basis in May of each year.

Our final decision is to amend CitiPower's TSS by:

- requiring stand-alone (grid scale) storage face network price signals to guide their operation and contribute to the cost of operating and maintaining the electricity distribution networks they use;
- specifying EV owners, once they are identified by the relevant network, will no longer have access to flat tariffs;
- clarifying that retailers can request tariff reassignment from distributors to help optimise their portfolios while consumers retain control over their retail offer;
- reducing the minimum chargeable demand for its HV customers from 1000 kVA to 500 kVA and sub-transmission customers from 10 000 kVA to 5000kVA;
- permitting it modifies its sub-transmission pricing structure to remain unchanged until our final decision on Australian Energy Market Operator's Designated pricing proposal charges pricing methodology in Victoria; and

[86] The regulatory control period (1 January 2016 to 31 December 2020) was extended by six months. Refer to the Executive Summary above for an overview of changes to the regulatory control period.

[87] NER, cl. 6.18.1A(a).

[88] NER, cl. 6.18.1A(e).

- providing greater detail on tariff trials in the first year of the regulatory control period.

These amendments complement the changes CitiPower already made to align with our draft decision. These changes include:

- reassignment of residential consumers on legacy time of use, flexibility and demand tariffs to the new time of use or demand equivalent,
- increasing the peak to off-peak ratio of the residential time of use tariffs to maintain the established ratios which incentivise consumers to respond,
- adopting United Energy’s incentive peak demand component into its large user tariff structure with transitional arrangements to help consumers adjust,
- providing greater clarity about continued access for consumers with consumption under 160 MWh a year but demand greater than 120 kVA to a zero demand tariff structure,
- refining large user peak charging windows to more closely target network conditions,
- provided further flexibility to allow large customers to be reassigned to the small business tariff class,
- providing greater clarity on how its tariff strategy aligned with distributed energy resource (DER) integration and demand management initiatives.

On large customer tariff choice, our final decision is to allow CitiPower to:

- not offer large user tariff choice at this time given the tight timelines between our draft decision and its revised proposal, as well as its intention to trial new large customer tariffs during the 2021–26 regulatory control period.

On energy storage, we consider batteries should contribute to recovery of network costs and should face network price signals to guide their operation. This will retain consistency with other National Electricity Market jurisdictions given the absence of new rules or policy direction between our draft and final decisions. If the asset falls into a particular tariff class, it should be assigned to the same network tariffs as other customers in that tariff class, whether owned by a distributor, its affiliate or a third party. We have amended CitiPower’s TSS to reflect this position. To the extent batteries are used for network support they are exempt from network tariffs, as they are currently.

We note the AEMC has foreshadowed its intention to consult with stakeholders on efficiently integrating distributed energy resources and that charging arrangements may be considered more generally in the context of the Energy Security Board reforms. The Victorian distributors have also committed to trialling new tariffs for energy storage over the 2021–26 regulatory control period.

Attachment 19 of this final decision provides detailed reasons for our decision on CitiPower's TSS.

6 Other price terms and conditions

In this section, we consider the other aspects of our determination. These may be described as the terms and conditions of our determination that cover how CitiPower must set its prices. This includes the classification of services and the framework for CitiPower's negotiated services.

6.1 Classification of services

Service classification determines the nature of economic regulation, if any, that is applicable to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and which services we will not regulate. Our decision reflects our assessment of a number of factors, including existing and potential competition to supply these services.

In its revised proposal, CitiPower accepted our draft decision on the classification of the services it provides.[89] Our final decision is to retain the classification structure and the services list as published in our draft decision for CitiPower.[90] The list of classified services CitiPower will provide for 2021–26 is set out in attachment 13 to this decision.

6.2 Negotiating framework and criteria

In our draft decision, we approved CitiPower's proposed distribution negotiating framework for the 2021–26 regulatory control period.[91] We did not receive any objections or submissions on our draft decision. Our final decision is to approve CitiPower's negotiating framework. The distribution negotiating framework that will apply to CitiPower for the period of this determination is set out in attachment A. We are also required to make a decision on the negotiated distribution service criteria (NDSC) for the distributor.[92] Our final decision is to retain the NDSC that we published for CitiPower in September 2020[93] for the 2021–26 regulatory control period. The NDSC gives effect to the negotiated distribution services principles.[94]

6.3 Connection policy

In our draft decision, we did not approve CitiPower's proposed connection policy for the 2021–26 regulatory control period. We modified CitiPower's connection policy nominated in its original proposal, to the extent necessary to enable it to be approved in accordance with the rules.

CitiPower accepted the majority of the changes we made to its initially proposed connection policy. However, it did not accept the threshold level for what size new connections needs to contribute the upstream cost in addition to the network extension

89 CitiPower, *Revised Regulatory proposal, 2021–26* - December 2020, p. 121.

90 AER, *Draft decision CitiPower distribution determination 2021–26*, *Attachment 12 Classification of services,* September 2020. The services list can be found in Attachment A

91 AER *Draft decision, CitiPower distribution determination 2021–26 - Attachment 17,* September 2020, p, 17-4.

92 NER, cl. 6.12.1(16).

93 AER, *Draft decision, CitiPower distribution determination 2021–26 - Attachment 17*, September 2020, p, 17-4.

94 NER, cl. 6.7.1.

cost set in the draft decision. CitiPower also proposed a new change to its original proposal to include the tax liability to the capital contribution for large embedded generator connections.

We do not agree to these proposed changes, because:

- CitiPower's proposed threshold is not consistent with our Connection Charge Guideline published under the NER, 100A 3 phase supply.
- CitiPower did not consult with the relevant stakeholders regarding the proposed change to include tax liability to the capital contribution for large embedded generator connections, since such change will result in a step change to its existing practice.

The approved connection policy for CitiPower's 2021–26 regulatory control period is appended to attachment 18 of our final decision.

7 The National Electricity Law and Rules

The NEL and NER provide the regulatory framework governing electricity distribution networks. Our work under this framework is guided by the NEO:[95]

> "…to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

The NEL requires us to make our decision in a manner that contributes, or is likely to contribute, to achieving the NEO.[96] The focus of the NEO is on promoting efficient investment in, and operation and use of, electricity services (rather than assets) in the long-term interests of consumers.[97] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[98]

Electricity determinations are complex decisions. In most cases, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. Where there are choices to be made among several plausible alternatives, we have selected what we are satisfied would result in an overall decision that is likely to contribute to the achievement of the NEO to the greatest degree.[99]

Our distribution determinations are predicated on a number of constituent decisions that we are required to make.[100] These are set out in appendix A and the relevant attachments. In coming to a decision that contribute to the achievement of the NEO, we have considered interrelationships of the constituent components of our final decision in the relevant attachments. Examples include:

- Underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 5 and 6).
- Direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3 and 7).

95 NEL, s. 7.

96 NEL, section 16(1)(a)

97 This is also the view of the Australian Energy Markets Commission (the AEMC). See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

98 Hansard, *SA House of Assembly,* 26 September 2013, p. 7173. See also the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 7–8.

99 NEL, s. 16(1)(d).

100 NER, 6.12.1

- Trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 5 and 6).

In general, we consider that the long-term interests of consumers are best served where consumers receive a reasonable level of safe and reliable service that they value at least cost in the long run.[101] A decision that places too much emphasis on short term considerations may not lead to the best overall outcomes for consumers once the longer term implications of that decision are taken into account.[102]

There may be a range of economically efficient decisions that we could make in a revenue determination, each with different implications for the long-term interests of consumers.[103] A particular economically efficient outcome may nevertheless not be in the long-term interests of consumers, depending on how prices are structured and risks allocated within the market.[104] There are also a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree than others would. For example, we consider that:

- The long-term interests of consumers would not be advanced if we encourage overinvestment which results in prices so high that consumers are unwilling or unable to efficiently use the network.[105]
- Equally, the long-term interests of consumers would not be advanced if allowed revenues result in prices so low that investors do not invest to sufficiently maintain the appropriate quality and level of service, and where consumers are making more use of the network than is sustainable leading to safety, security and reliability concerns.[106]

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101 Hansard, *SA House of Assembly,* 9 February 2005, p. 1452.

102 See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p.6–7.

103 *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].

104 See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

105 NEL, s. 7A(7).

106 NEL, s. 7A(6).

A Constituent decisions

Constituent decision
In accordance with clause 6.12.1(1) of the NER, the AER's final decision is that the classification of services set out in Attachment 13 will apply to CitiPower for the 2021–26 regulatory control period.
In accordance with clause 6.12.1(2)(i) of the NER, the AER's final decision is not to approve the annual revenue requirement set out in CitiPower building block proposal. Our final decision on CitiPower's annual revenue requirement for each year of the 2021–26 regulatory control period is set out in Attachment 1 of the final decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve CitiPower's proposal that the regulatory control period will commence on 1 July 2021. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve CitiPower's proposal that the length of the regulatory control period will be five years from 1 July 2021 to 30 June 2026.
The AER did not receive a request for an asset exemption under clause 6.4.B.1 (a) (1) and therefore has not made a decision in accordance with clause 6.12.1(2A) of the NER.
In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(d) of the NER, the AER's final decision is not to accept CitiPower's proposed total forecast capital expenditure of $633.3 million ($2020–21). Our final decision therefore includes a substitute estimate of CitiPower's total forecast capex for the 2021–26 regulatory control period of $589.9 million ($2020–21). The reasons for our final decision are set out in Attachment 5.
In accordance with clause 6.12.1(4)(i) of the NER and acting in accordance with clause 6.5.6(c), the AER's final decision is to accept CitiPower’s proposed total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIAM of $476.7 million ($2020–21). The reasons for our final decision are set out in Attachment 6.
CitiPower did not propose any contingent projects and therefore the AER has not made a decision under clause 6.12.1(4A) of the NER.
In accordance with clause 6.12.1(5) of the NER and the modified 2018 Rate of Return Instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs set out in the Order in Council made under section 16VE of the amended National Electricity (Victoria) Act 2005 (Vic), the AER's final decision is that the allowed rate of return for the 2021–22 regulatory control year is 4.73 per cent (nominal vanilla) as set out in Attachment 3 of the final decision. The rate of return for the remaining regulatory years 2022–26 will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
In accordance with clause 6.12.1(5A) of the NER and the modified 2018 Rate of Return Instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs set out in the Order in Council made under section 16VE of the amended National Electricity (Victoria) Act 2005 (Vic), the AER's final decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.585. This is discussed in Section 2.2 of this final decision overview.

Constituent decision

In accordance with clause 6.12.1(6) of the NER, the AER's final decision on CitiPower's regulatory asset base as at 1 July 2021 in accordance with clause 6.5.1 and schedule 6.2 is $1968.9 million ($ nominal). This is discussed in Attachment 2 of the final decision.

In accordance with clause 6.12.1(7) of the NER, the AER's final decision on the estimate of CitiPower's corporate income tax is $36.3 million ($ nominal) for the 2021–26 regulatory control period. This comprises ($ nominal):

- $8.2 million in 2021-22,
- $7.4 million in 2022-23,
- $6.1 million in 2023-24,
- $7.2 million in 2024-25 and
- $7.4 million in 2025-26.

This is discussed in Attachment 7 of the final decision.

In accordance with clause 6.12.1(8) of the NER, the AER's final decision is to not approve the depreciation schedules submitted by CitiPower. Our final decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b) and this is discussed in Attachment 4 of the final decision.

In accordance with clause 6.12.1(9) of the NER the AER makes the following final decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), service target performance incentive scheme (STPIS), demand management incentive scheme (DMIS), demand management innovation allowance mechanism (DMIAM) or small-scale incentive scheme (customer service incentive scheme) is to apply:

- We will apply version 2 of the EBSS to CitiPower in the 2021–26 regulatory control period. This is discussed in Attachment 8 of the final decision.
- We will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to CitiPower in the 2021–26 regulatory control period. This is discussed in Attachment 9 of the final decision.
- We will apply our Service Target Performance Incentive Scheme (STPIS) to CitiPower for the 2021–26 regulatory control period. This is discussed in Attachment 10 of the final decision.
- We will apply the DMIS and DMIAM to CitiPower for the 2021–26 regulatory control period. This is discussed in overview of the final decision.
- We will apply the CSIS to CitiPower for the 2021–26 regulatory control period. This is discussed in Attachment 12 of the draft decision.

In accordance with clause 6.12.1(10) of the NER, the AER's final decision is that all other appropriate amounts, values and inputs are as set out in this final determination including attachments.

In accordance with clause 6.12.1(11) of the NER and our framework and approach paper, the AER's final decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for CitiPower for any given regulatory year is the total annual revenue calculated using the formulae in attachment 14, which includes any adjustment required to move the DUoS unders and overs account to zero. This is discussed in Attachment 14 of the final decision.

Constituent decision

In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's final decision on the form of the control mechanism for alternative control services is to apply a revenue cap for type 5 and 6 metering (including smart metering) services and price caps for all other services. The revenue cap for CitiPower's type 5 and 6 metering (including smart metering) services for any given regulatory year is the total annual revenue for type 5 and 6 (inc. smart metering) services calculated using the formulae in Attachment 14, which includes any adjustment required to move the metering unders and overs account to zero. This is discussed in Attachment 14 of the final decision.

In accordance with clause 6.12.1(13) of the NER, to demonstrate compliance with its distribution determination, the AER's final decision is that CitiPower must maintain a DUoS unders and overs account and a metering unders and overs account. It must provide information on these accounts to us in its annual pricing proposal. This is discussed in Attachment 14 of the final decision.

In accordance with clause 6.12.1(14) of the NER, the AER's final decision is to apply the following nominated pass through events to CitiPower for the 2021–26 regulatory control period in accordance with clause 6.5.10:

- Terrorism event
- Insurance coverage event
- Natural disaster event
- Insurer credit risk event
- Retailer insolvency event

These events have the definitions set out in Attachment 15 of the final decision.

In accordance with clause 6.12.1(14A) of the NER, the AER's final decision is to not approve the tariff structure statement proposed by CitiPower. This is discussed in Attachment 19 of the final decision.

In accordance with clause 6.12.1(15) of the NER, the AER's final decision is that the negotiating framework as proposed by CitiPower will apply for the 2021–26 regulatory control period. This is discussed in section 6.2 of this final decision overview and the negotiating framework is in Attachment A of this final decision.

In accordance with clause 6.12.1(16) of the NER, the AER's final decision is to apply the negotiated distribution services criteria published, as published in our draft decision in September 2020 to CitiPower. This is set out in section 6.2 of this final decision overview.

In accordance with clause 6.12.1(17) of the NER, the AER's final decision on the procedures for assigning and reassigning retail customers to tariff classes for CitiPower is set out in Attachment 19 of the final decision.

In accordance with clause 6.12.1(18) of the NER, the AER's final decision is that the depreciation approach based on forecast capex (forecast depreciation) is to be used to establish the RAB at the commencement of CitiPower' regulatory control period as at 1 July 2026. This is discussed in Attachment 2 of the final decision.

In accordance with clause 6.12.1(19) of the NER, the AER's final decision on how CitiPower is to report to the AER on its recovery of designated pricing proposal charges for each regulatory year of the 2021–26 regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges is to set

Constituent decision
this out in its annual pricing proposal. The method report recovery of the charges and to account for the under or over recovery of designated pricing proposal charges is discussed in Attachment 14 of the final decision.
In accordance with clause 6.12.1(20) of the NER, the AER's final decision on how CitiPower is to report to the AER on its recovery of jurisdictional scheme amounts for each regulatory year of the 2021–26 regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges is to set this out in its annual pricing proposal. The method to report recovery of the charges and account for the under or over recovery of jurisdictional scheme amounts is discussed in Attachment 14 of the final decision.
In accordance with clause 6.12.1(21) of the NER, the AER's final decision is to not approve the connection policy proposed by CitiPower. Our final decision is to amend CitiPower' proposed connection policy as set out in Attachment 18 of the final decision.
In accordance with section 16C of the National Electricity (Victoria) Act 2005, the NEL, the NER and the "f-factor scheme order 2016"[107], the AER's final decision is to apply the f-factor incentive payments/penalties as a part of the "I-factor" adjustment to the calculation of the total annual revenue requirement using the formulae in Attachment 14 of the final decision.

107 See http://www.gazette.vic.gov.au/gazette/Gazettes2016/GG2016G051.pdf, Victoria Government Gazette, G 51 22 December 2016, p. 3239.

B List of submissions

We received public submissions from the following stakeholders on our draft decision and CitiPower's revised proposal:

Stakeholder
AGL
Ausgrid
Consumer Challenge Panel 17
Electric Vehicle Council
EnergyAustralia
Energy Consumers Australia
Energy Users Association of Australia
Evie Networks
Firm Power
Groundline Engineering
Jemena Electricity Networks People's Panel
Local Government Response, prepared by Victorian Greenhouse Alliances
Origin Energy
Red Energy and Lumo Energy
Victorian Community Organisations, prepared by Brotherhood of St Laurence, Renew, Victorian Council of Social Service

C Consumer engagement framework

The following table represented the framework outlined in our draft decision for considering consumer engagement.[108]

Element	Examples of how this could be assessed
Nature of engagement	• Consumers partner in forming the proposal rather than asked for feedback on distributor's proposal • Relevant skills and experience of the consumers, representatives, and advocates • Consumers provided with impartial support to engage with energy sector issues • Sincerity of engagement with consumers • Independence of consumers and their funding • Multiple channels used to engage with a range of consumers across a distributor's consumer base
Breadth and depth	• Clear identification of topics for engagement and how these will feed into the regulatory proposal • Consumers consulted on broad range of topics • Consumers able to influence topics for engagement • Consumers encouraged to test the assumptions and strategies underpinning the proposal • Consumers were able to access and resource independent research and engagement
Clearly evidenced impact	• Proposal clearly tied to expressed views of consumers • High level of business engagement, e.g. consumers given access to the distributor's CEO and/or board • Distributors responding to consumer views rather than just recording them • Impact of engagement can be clearly identified • Submissions on proposal show consumers feel the impact is consistent with their expectations

Proof point	• Reasonable opex and capex allowances proposed
	    ○ In line with, or lower than, historical expenditure
	    ○ In line with, or lower than, our top down analysis of appropriate expenditure
	    ○ If not in line with top down, can be explained through bottom up category analysis

[108] AER, Draft decision, *CitiPower distribution determination 2021–26, Overview*, September 2020, Table 7, p. 42.

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
CESS	capital expenditure sharing scheme
CPI	consumer price index
DER	distributed energy resources
DMIAM	demand management innovation allowance mechanism
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
EV	electric vehicle
NEL	National Electricity Law
NELA	National Energy Legislation Amendment Act 2020 (Vic)
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital
VCO	Victorian Community Organisations